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Precursors to Potential Severe Core Damage Accidents: 1969-1979
A Status Report

Main Report
Appendices A, C, D, and E

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Prepared for
U.S. Nuclear Regulatory Commission
Office of Nuclear Regulatory Research

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PRECURSORS TO POTENTIAL SEVERE CORE DAMAGE ACCIDENTS: 1969-1979
A STATUS REPORT

Main Report and
Appendices A, C, D and E

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Science Applications, Inc.

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NOTE

This document is bound in two volumes: Vol. 1 contains the main report and Appendixes A, C, D, and E; Vol. 2 contains Appendix B.

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FOREWORD

This report presents the initial results of a program that was begun as a result of one of the Lewis Committee recommendations following their review of WASH-1400, the *Reactor Safety Study*. One of the committee's review findings was that more use should be made of operational data to assess the risk from nuclear power plants. The Precursor Program, performed at Oak Ridge National Laboratory and administered by the Nuclear Regulatory Commission, responds to this Lewis committee finding. The Precursor Program uses Licensee Event Reports to evaluate potential nuclear plant accident precursors occurring at operating reactors. These individual plant precursors are then summarized to evaluate the risk (for a particular time period) from all operating nuclear power plants. This report, covering 1969–1979 LERs, is being released as a progress report with the expectation that some conclusions may need to be changed as the report undergoes continuing peer review and public comment. The next report (using 1980–1981 LER data) should reflect the risk from nuclear plants since the TMI-2 accident and may show what effects new procedures and equipment modifications (lessons learned) have had.

In addition to the documentation of 169 identified precursors and preliminary trends analyses, the report estimates the frequency of severe core damage based on the precursor information. It is a difficult problem to derive a credible probability for severe core damage using limited operational experience data from plants that have many significant physical and operational differences among them. The authors of this report partially account for plant differences by using generalized (functional) event trees for individual precursor evaluation, which in their quantification are then specialized, as much as possible, to the particular plant. Nonetheless, simplified methods are used to determine and quantify severe core damage precursors. Several aspects of this report are expected to affect the calculated results, either conservatively or nonconservatively. The first two of the following items are expected to introduce a conservative and nonconservative bias, respectively. The remaining items may introduce either conservative or nonconservative biases.

- The probability of subsequent core damage given the precursor may be conservative in some cases.
- The LER screening process may have overlooked precursors that should have been included.
- The accuracy and completeness of the LERs in reflecting pertinent operational failure or initiating events is somewhat questionable.
- The event trees used for most precursors are generic and may not adequately reflect differences among plants.
- Average or generic data are combined with plant-specific operational occurrences in calculating the probability of subsequent severe core damage.
- The repair (recovery) credit for system failure involves engineering judgment.
- The method used to calculate the frequency of severe core damage is subject to various interpretations because of the combined use of event

statistics and generic initiating event and function failure probabilities.

The use of LERs to attempt to extract severe core damage probabilities, on a scale and to the detail such as done in this report, is unique. The full meaning and limitations of the severe core damage calculations made in this report are not clear. It is felt, however, that the report provides valuable information that can help validate or supplement probabilistic risk assessments performed on nuclear power plants. Much of the basic data and information needed for additional calculations or inferences of reactor risk by the reader is included in the report. As mentioned, this report will be followed by other reports that will evaluate LERs in the 1980-1981 time period and also will provide further analysis, refinement, and practical use of the basic data contained within this report.

Reader comments and suggestions are earnestly solicited and should be sent to the Chief, Reactor Risk Branch, Division of Risk Analysis, at the address below.

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Division of Risk Analysis
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
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PREFACE

The work reported here was undertaken by the Nuclear Operations Analysis Center at Oak Ridge National Laboratory on behalf of the Division of Risk Analysis of the Nuclear Regulatory Commission. The FY-1982 NRC technical monitor, F. M. Manning, succeeded M. A. Taylor, who was technical monitor until his reassignment in November 1981. The work on accident sequence precursors was initiated early in 1979 with R. L. Scott as project manager, assisted by the authors of this report. However, when Scott was reassigned in July 1980, J. W. Minarick became acting manager and has retained that role since. Both Minarick and C. A. Kulkielka are Science Applications, Inc., employees and performed their work under subcontract to NOAC. Most of the work was performed at NOAC offices because of the availability of relevent documents and technical support. The training and background of these authors well qualified them for the task. Minarick, an electrical engineer, has had 12 years of reactor systems experience, including 5 years on Admiral H. G. Rickover's staff and 3.5 years with Babcock & Wilcox Company. Kulkielka, who received his M.S. degree in nuclear engineering in 1979, had 2 years' prior experience with the U.S. Army nuclear program before joining SAI in 1979.

This status report covers the first 2.5 years of effort. The work involved (1) development of selection criteria for the identification of those reactor events that are precursors of potential severe core damage, (2) application of these criteria against all the licensee event reports that have been received since 1969, and (3) detailed analyses of the selected events. This report covers the work completed for LERs submitted during the 11-year period from 1969 to 1979. Although the NRC has previously reviewed the selection criteria and the events selected, it has not been directly involved in the application of these criteria against the existing LERs. This task has been performed entirely by the NOAC staff, using its best judgment in doing so. While this judgment reflects many years of experience in reactor design, reactor operations, and systems evaluations, the process is subjective, and not all specialists will necessarily agree with every event selected and/or omitted.

This report deals only with historical data and, at this point, with minimal statistical interpretation. The TMI-2 accident is responsible for about half the core damage frequency value estimated herein. Yet, could one say — given the conditions of early 1979 — that the frequency of a TMI-2-type accident at that time was once every 4 years or once every 100 years? Furthermore, the same selection criteria that were used in this study would also have been applicable had the top event been severe fuel cladding failure, severe core damage, or core meltdown. In any event, the many changes that have occurred in nuclear plant design and operation since 1979 are expected to substantially reduce the future probability of all such events.

Continuing work on this program is expected to include:

- an assessment of the uncertainty in the core damage probability calculations (a simplified approach, based on the fact that TMI-2 has been the only true core damage statistic, indicates the report estimate could be too low by a factor of 2 to 3 or too large by one or two orders of magnitude) and

- a calculation of the probability of severe core damage accidents based on the ~7500 LERs submitted in 1980 and 1981.

Inevitably, the results of this report will be compared with the data in the *Reactor Safety Study* (WASH-1400) and other probabilistic risk assessment studies. Although the casual reader may interpret the Accident Sequence Precursor study results as incompatible with other core damage estimates, it is quite likely that because of the statistical uncertainty, no significant difference exists. That, of course, remains to be demonstrated.

In conclusion, I direct your attention to the various trends analyses included in this report. Although the statistical precision is not great, the trends are of considerable interest. In any event, the results presented here indicate how very important it is that the operating experience be analyzed for trends that a more casual surveillance of such experience might not reveal.

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LIST OF ACRONYMS AND INITIALISMS

ADS	automatic depressurization system
AFW	auxiliary feedwater
AIF	Atomic Industrial Forum
ASP	Accident Sequence Precursor
BIT	boron injection tank
BWR	boiling-water reactor
BWST	borated water storage tank
B&W	Babcock & Wilcox
CRDM	control rod drive mechanism
CS	core spray
D	demand
DG	diesel generator
ECCS	emergency core cooling system
ESFAS	engineered safety features actuation system
FSAR	Final Safety Analysis Report
HPCI	high-pressure coolant injection
HPI	high-pressure injection
IC	isolation condenser
LER	Licensee Event Report
LOCA	loss-of-coolant accident
LOFW	loss of main feedwater
LOOP	loss of offsite power
LPCI	low-pressure coolant injection
LPR	low-pressure recirculation
MSIV	main steam isolation valve
NNI	nonnuclear instrumentation
NOAC	Nuclear Operations Analysis Center
NRC	Nuclear Regulatory Commission
NSIC	Nuclear Safety Information Center
ORNL	Oak Ridge National Laboratory
PORV	pilot-operated relief valve
PRA	probabilistic risk assessment
PWR	pressurized-water reactor
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RPS	reactor protection system
RWST	refueling water storage tank
SAI	Science Applications, Inc.
SBLC	standby liquid control
SFAS	safety features actuation system
SFRCS	steam and feedwater rupture control system
SI	safety injection
SLB	steam line break
SLBIC	steam line break instrumentation and control
TMI-2	Three Mile Island, Unit 2

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REPORT SUMMARY

The Accident Sequence Precursor study involves the review of Licensee Event Reports of operational events that have occurred at light-water power reactors to identify and categorize precursors to potentially significant accident sequences. Accident sequences considered in the study are those that could lead to severe core damage. Accident sequence precursors of interest are events that are important elements in a chain of events (an accident sequence) possibly leading to core damage. Such precursors might be infrequent initiating events or equipment failures that, when coupled with one or more postulated events, could result in a plant condition leading to severe core damage.

A nuclear plant has safety system equipment for mitigating accidents or off-normal initiating events that may occur during the course of plant operation. These safety systems are built to high quality and are redundant; nonetheless, they have a definite probability of failing or being in a failed state when required to operate. This report uses LERs and other plant data to calculate the unavailability of plant safety systems. It then uses these calculated safety system unavailabilities and the expected average frequency of initiating events (loss of feedwater, loss of offsite power, loss-of-coolant accidents, and steam line breaks, also determined when possible from the precursors) to evaluate the end results of safety system unavailability for two situations:

1. Safety system failures without initiating events. Given an LER-reported failure of a safety system or partial failures in several systems, the report uses expected initiating event occurrence rates to determine the number of initiating events that will challenge the failed and backup safety systems during the period the safety system is failed. It multiplies the challenges by system failure probabilities, using event trees to evaluate the likelihood of the overall event sequence occurring.

2. Initiating event occurrences. Although standby safety systems are ideally always available, there is a statistical probability that these systems will fail when called on to mitigate expected accident or transient initiating events. Therefore, the report calculates the likelihood of severe core damage occurrence for each LER-reported initiating event based on expected response (failure probabilities) of the safety systems. Failed or degraded safety systems existing at the time of the initiating event are accounted for in the calculations.

The study effort has been divided into several tasks, which are described in detail in later sections of this report. These tasks include (1) selection of LERs for detailed review as precursors; (2) in-depth review of those LERs; (3) identification, description, and categorization of events considered to be precursors; (4) selection of precursors considered significant; and (5) subsequent analysis of the precursors to determine if any trends or unique relationships exist among them.

For this study, LER events were selected as precursors if they met one of the following requirements:

1. The event involved the failure of at least one function required to mitigate an initiating event of interest.

2. The event involved the degradation of more than one function required to mitigate an initiating event of interest.

3. The event involved an unusual actual initiating event (e.g., a total loss of offsite power, a stuck-open primary relief valve, or another infrequent event).

Approximately 19,400 LERs concerning events that occurred during 1969–1979 were screened for accident sequence precursors according to the above requirements. Of these, over 500 LERs (~3%) were selected for detailed review.

All LERs selected for detailed review were subjected to an in-depth evaluation, which included

1. a review of the accident sequence (if there was one) as described in the LER,

2. a review of the design of systems in the reactor plant reporting the LER to determine the impact of the failure on the operation of these systems, and

3. a review of the plant accident analyses to determine the extent to which affected systems would be required to function for different off-normal and accident conditions.

As a result of this detailed review, 169 events were selected as accident sequence precursors. For each of these events, four items were prepared: a sheet describing the event, a categorization sheet including event- and reactor-specific information used in subsequent analyses, and two event trees. The first event tree describes the actual occurrence as reported in the LER and identifies the potential for severe core damage stemming from the actual event. The second event tree describes a postulated sequence of events that *could* have been affected by the actual reported failures. A set of these four items for each of the 169 events is included in Appendix B.

The failure information contained in the precursors was used to estimate initiating event frequencies and function failure-on-demand probabilities. This information was used, in conjunction with the precursor event trees, to determine a measure of the probability of severe core damage associated with each event sequence. This probability is an estimate of the chance of severe core damage given the precursor event occurred in the manner it did. These probability measures were then used to rank the precursors. Fifty-two precursors with probability measures of $\geq 10^{-3}$ were selected as significant.

The probabilities of severe core damage associated with the precursors were also used to estimate the frequency of severe core damage per reactor year *for the years 1969–1979.* This point estimate is between 1.7×10^{-3} and 4.5×10^{-3} per reactor year and includes contributions from three major events: (1) the loss of feedwater and stuck-open relief valve at Three Mile Island Unit 2 (which actually resulted in severe core damage), (2) the loss of nonnuclear instrumentation at Rancho Seco, and (3) the fire in the cable spreading room at Browns Ferry 1.

These numbers are compared with other estimates from PRAs and from the TMI-2 event alone in Fig. 1.

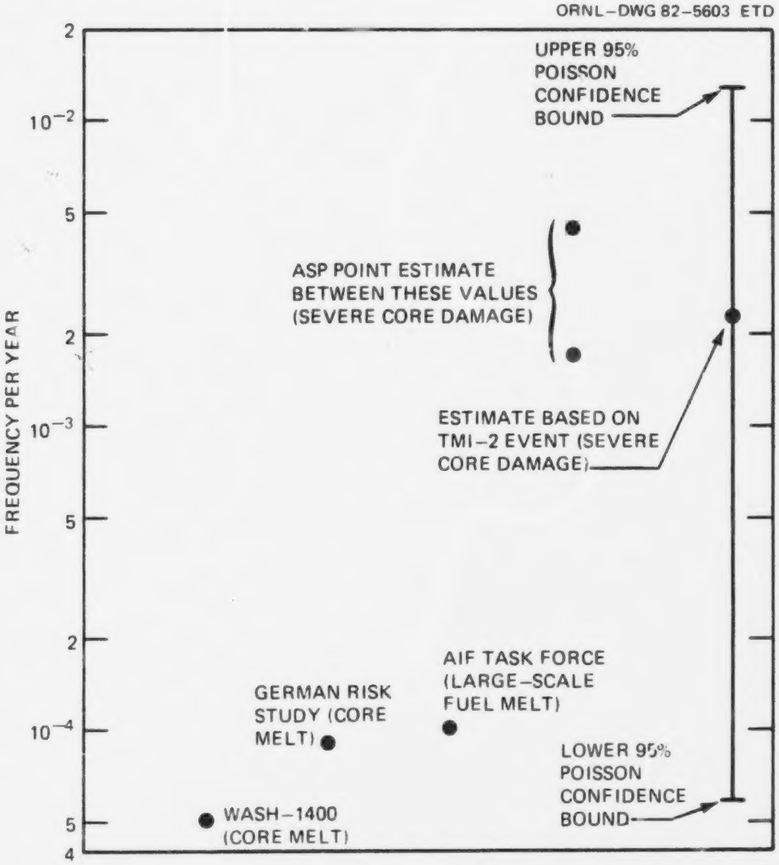

Fig. 1. Comparison of ASP results with other core damage estimates.

Subsequent analyses of the information included in the selected precursors resulted in the following additional conclusions:

1. Many of the initiating event frequencies and function failure-on-demand probabilities developed from operational event information agree reasonably well (within a factor of 10) with the *Reactor Safety Study*[1] median results.
2. A variation in the rate of occurrence of significant precursors per plant as a function of plant age cannot be justified.
3. Differences do not appear to exist in the number of significant precursors observed between plant types and among reactor vendors, architect-engineers, and plant power ratings.
4. Approximately 38% of all significant precursors involved human error.

These analyses did not involve extreme statistical sophistication but were first attempts to determine if trends were discernible in the selected events. Changes made in reactor plant operation after the TMI-2 accident (particularly the potential use of high-pressure injection following auxiliary feedwater system failure and the ability to provide flow from at least one auxiliary feedwater pump during a loss of ac power in PWRs) are expected to reduce this estimate considerably in later years.

For reference, highlights of this study are summarized in Table 1.

Table 1. Accident Sequence Precursor study highlights

Period covered	1969–1979
Total number of LERs searched	19,400
Number selected for detailed review	529
Number selected as precursors	169
Number of significant events	52

A point estimate of the frequency of severe core damage calculated from precursor information for the years 1969–1979 lies between 1.7 x 10^{-3} and 4.5 x 10^{-3} per reactor year.

Reasonable agreement exists between ASP and *Reactor Safety Study* initiating event frequencies and function failure probabilities.

No variation with plant age can be demonstrated in the number of significant events.

No apparent differences exist between plant types and among vendors, architect-engineers, and plant power ratings.

Reference

1. U.S. Nuclear Regulatory Commission, *Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants*, WASH-1400 (NUREG-75/014) (October 1975).

PRECURSORS TO POTENTIAL SEVERE CORE DAMAGE ACCIDENTS: 1969–1979 A STATUS REPORT

J. W. Minarick*   C. A. Kukielka*

ABSTRACT

Descriptions of 169 operational events reported as Licensee Event Reports, which occurred at commercial light-water reactors during 1969–1979 and which are considered to be precursors to potential severe core damage, are presented, along with associated event trees and categorizations and subsequent analyses. The report summarizes work in (1) the development of methods used to screen ~19,400 LER abstracts for potential precursors, (2) the initial screening of those abstracts to determine which should be reviewed in detail, (3) the detailed review of those selected LERs that yielded the 169 events, (4) the categorization of the 169 events, (5) the calculation of function failure estimates based on precursor data, (6) the use of probability of severe core damage estimates to rank precursor events and estimate the frequency of severe core damage, (7) the identification of 52 events considered significant, (8) trends analyses of those significant events, and (9) the identification of the other events of interest that occurred within 1 month of significant events.

1. INTRODUCTION

The Accident Sequence Precursor study involves the review of Licensee Event Reports of operational events that have occurred at light-water power reactors between 1969 and 1981 to identify and categorize precursors to potential severe core damage accident sequences. This progress report details this effort for 1969–1979 LERs. Although Licensee Event Reports were not required until mid-1975, event reports comparable to LERs existed before the inception of the LER system and are considered to be LERs for the purpose of this study. [The requirements of Licensee Event Reports are described in Regulatory Guide 1.16 (Ref. 1).] Work on the ASP study began at the Nuclear Safety Information Center on June 15, 1979, in response to FY-1979 Nuclear Regulatory Research Order 60-79-185, "Accident Sequence Precursor Study" dated June 7, 1979, and subsequent orders.

The program was initiated, in part, because of conclusions contained in the *Risk Assessment Review Group Report*.[2] This report states "that unidentified event sequences significant to risk might contribute . . . a small increment . . . [to the overall risk]." The report recommends: "It is important, in our view, that potentially significant (accident) sequences, and precursors, as they occur, be subjected to the kind of analysis contained in WASH-1400 [Ref. 3]. . . ."

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*Science Applications, Inc.

Accident sequences considered in the study are those that could lead to severe core damage. Accident sequence precursors of interest are events that are important elements in a chain of events (an accident sequence) possibly leading to core damage. Such precursors could be infrequent initiating events or equipment failures that when coupled with one or more postulated events, could result in a plant condition leading to severe core damage.

Note that the results achieved in this report have been obtained based on events reported in LERs and subsequently selected as precursors. Because of the use of LERs, biases may have been introduced as a result of differences in plant technical specifications and approaches to LER reporting and of changes in LER reporting requirements over the period of the study. These considerations may result in the failure to include certain events that under different circumstances would have been selected for inclusion. However, the events selected were more serious than most, and it is expected that most of these would have been reported independently of small differences in reporting requirements.

The ASP study effort has been divided into the following tasks:

1. selection of LERs deserving a detailed review as precursors;
2. detailed review of selected LERs;
3. identification, description, and categorization of events considered accident sequence precursors;
4. selection of precursors that are considered significant; and
5. analysis of precursors to determine if any trends or unique relationships exist.

These tasks are described in detail in the following sections.

References

1. U.S. Nuclear Regulatory Commission, *Regulatory Guide 1.16, Reporting of Operating Information, Appendix A: Technical Specifications*, Rev. 4 (August 1975).

2. U.S. Nuclear Regulatory Commission, *Risk Assessment Review Group Report*, p. 15, NUREG/CR-0400 (September 1978).

3. U.S. Nuclear Regulatory Commission, *Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants*, WASH-1400 (NUREG-75/014) (October 1975).

2. CRITERIA FOR SELECTION OF LERs FOR DETAILED REVIEW AS PRECURSORS

Identification of those 1969–1979 LERs that required a detailed review as precursors was made based on an examination of the abstract for each LER. Approximately 19,400 LER abstracts were examined, and specific LERs were chosen if any of the following criteria were met:

1. any failure to function of a system that should have functioned as a consequence of an off-normal event or accident,
2. any instance where two or more failures occurred,
3. all events that resulted in or required initiation of safety-related equipment (except events that only required trip and when trip was successful),
4. all complete losses of offsite power and any less frequent off-normal initiating events or accidents,
5. any event or operating condition that was not enveloped by or proceeded differently from the plant design bases, and
6. any other event that, based on the reviewer's experience, could have resulted in or significantly affected a chain of events leading to potential severe core damage.

It was recognized that such criteria might not describe all LERs that should be selected for a detailed review. Conversely, rigidly applying these criteria would result in selection of certain LERs that were clearly not important. An example of this would be an event involving two failures occurring in one train of a redundant system. Such an event, while involving two failures, would have no further impact on system performance than either of the two failures taken separately. Because of this, the criteria were used as a basis for determining which LERs were most likely deserving of detailed review.

For two reasons, only events that occurred after criticality were selected for detailed review: (1) a core was considered vulnerable to severe core damage only after criticality and (2) in the precritical period, distinguishing initial testing (system-checkout) failures from operational failures was sometimes difficult. Additionally, because the study was concerned only with operational failures, design errors discovered by reanalysis were not considered.

Three potential sources of error in selecting LERs for detailed review follow.

1. Inherent biases in the selection process. Although the criteria for subsequent identification of an LER as a precursor, once the LER is selected for detailed review, is fairly well defined, the selection of an LER for review is somewhat judgmental. Events selected in the study were more serious than most, and it is expected that the majority of the LERs selected for detailed review would have been selected by other reviewers

with experience in light-water reactor systems and their operation. However, some differences would be expected to exist; thus, the selected set of precursors should not be considered unique.

2. Lack of appropriate information in the LER abstracts. The LER abstracts stored in the NSIC data file are based on a written abstract of the event provided in the LER rather than a detailed review of each LER event. If the abstract of a potentially important LER does not show that the LER deserves review, then it will likely be missed.

3. Specificity of the LER reporting system. Licensee Event Reports are required to be filed when plant Technical Specifications are violated or limiting conditions of operation are entered. These requirements are described in Regulatory Guide 1.16 (Ref. 1) and are dependent on the detailed wording of each plant's Technical Specifications. Because of this, certain events of interest may not be reported. The scope of this study included only events reported via the LER system.

A total of 529 LERs (2.7%) out of ~19,400 dated 1969–1979 were selected for detailed review as precursors to potential severe core damage accidents.

Reference

1. U.S. Nuclear Regulatory Commission, *Regulatory Guide 1.16*, *Reporting of Operating Information*, *Appendix A: Technical Specifications*, Rev. 4 (August 1975).

3. DETAILED REVIEW AND IDENTIFICATION OF SELECTED LERs AS ACCIDENT SEQUENCE PRECURSORS

The LERs identified in the initial screening and selection process were subjected to an in-depth review to identify those operational events considered to be precursors to potential severe core damage accidents, either as initiating events or as failures that could have affected the course of postulated off-normal events or accidents. These detailed reviews used Final Safety Analysis Reports, their amendments, and other information available at NSIC.

The detailed review of each LER considered (1) the immediate impact of the initiating event, equipment failures, or operator errors on plant operation and (2) the impact of the equipment failures or operator errors on readiness of systems in the plant for mitigation of off-normal and accident conditions.

In the review of each selected LER, three general scenarios (involving both the actual event and postulated additional failures) were considered.

1. If the LER initiating event or failure was immediately detectable and occurred while the plant was at power (e.g., if it initiated a transient), then the LER event was evaluated according to the likelihood that the event and the ensuing plant response could lead to severe core damage.

2. If the LER event was immediately detectable but occurred while the plant was not at power, then the event was evaluated according to the likelihood that the event plus the plant response, had it occurred while at power or at hot shutdown immediately following power operation, could lead to severe core damage.

3. If the LER event had no immediate effect on plant operation (e.g., if two pumps were found failed in testing), then the event was evaluated based on the likelihood of severe core damage from a postulated initiating event (during the failure period) that required the failed items for mitigation. This was done because the plant would be vulnerable to expected initiating events such as a loss of offsite power or loss-of-coolant accident during the length of time between an equipment failure and its detection.

The initiating events chosen for the postulated sequences were, in general, the most likely off-normal or accident initiators that would involve the reported failure. One of the following postulated initiating events was used in most cases:

1. loss of main feedwater,
2. loss of offsite power,
3. loss-of-coolant accident, and
4. steam line break accident.

The first two postulated events were chosen because they are the most common off-normal initiating events that require safety system initiation. The two accidents are not expected to occur frequently but represent

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bounding events for certain safety-related systems not challenged during the first two events. Unique initiating events were used in the postulated sequences of interest when necessary during this review.

For each actual occurrence or postulated initiating event associated with an LER event, the sequence of operation of various mitigating functions required to prevent severe core damage was considered. In general, if the mitigation sequence contained a complete loss of one of the sequence functions or degraded performance of multiple sequence functions required to prevent severe core damage, then the LER was accepted as a precursor. In addition, infrequent initiating events that required safety system response, such as a total loss of offsite power or a stuck-open primary relief valve (a small LOCA), were also selected as precursors.

The 169 LER events for the years 1969–1979 that were identified as precursors to potential severe core damage accidents are identified in Table 3.1. The precursor events have been arranged in numerical order by NSIC accession number, and the following information is included:

1. NSIC accession number associated with each precursor,
2. date of the event,
3. postulated sequence of interest associated with the event,
4. a brief description of the event,
5. docket number and plant name where the event occurred,
6. abbreviations for the system and component involved in the event,
7. plant operating status at the time of the event,
8. discovery method associated with the event (operational or testing),
9. involvement of human error,
10. association of a transient or accident with the precursor,
11. age of the plant from criticality (in days) at the time of the event,
12. significance category associated with the event (defined in Chap. 4),
13. plant electrical rating, type, vendor, architect-engineer, and licensee,
14. plant criticality date, and
15. indefinite shutdown of the plant (where applicable).

Abbreviations used within the table are defined at the end of the table.

For each of the 169 LERs selected as precursors, four items were prepared (found in Appendix B): (1) a precursor description and data sheet, (2) a categorization of accident sequence precursors sheet, (3) an event tree describing the actual occurrence, and (4) an event tree for a postulated sequence of interest that incorporates the significant aspects of the actual occurrence. A description of each of these items follows.

1. Precursor description and data sheet (Fig. 3.1) briefly describes the LER event, identifies what corrective action was taken after the event, describes the purpose of the failed system or component, and lists the unavailability of equivalent systems and components as determined in the *Reactor Safety Study*.[1]

Table 3.1. Precursors listed by NSIC accession number

TABLE COLUMN HEADING ABBREVIATIONS

ACCESS: 6 DIGIT NSIC ACCESSION NUMBER
E DATE: EVENT DATE
SEQ: SEQUENCE OF INTEREST FOR THE EVENT
ACTUAL OCCURRENCE: DESCRIPTION OF EVENT
PLANT NAME: NAME OF PLANT AND UNIT NUMBER
DOC: PLANT DOCKET NUMBER
SY:SYSTEM ABBREVIATION:
COMPXX: SYSTEM COMPONENT CODE:
O: PLANT OPERATING STATUS:
D: DISCOVERY METHOD (O-OPERATIONAL EVENT, T-TESTING)
E: HUMAN ERROR INVOLVED (N-NO, Y-YES)

I: TRANSIENT/ACCIDENT INDUCED BY ACTUAL OCCURRENCE (N-NO, Y-YES)
AGEX: PLANT AGE AT THE TIME OF THE EVENT IN DAYS
SC: SIGNIFICANCE CATEGORY
RATE: PLANT ELECTRICAL RATING IN MEGAWATTS ELECTRIC
T: PLANT TYPE (B=BWR, P=PWR)
V: PLANT NSSS VENDOR
AE: PLANT ARCHITECT ENGINEER
OPR: PLANT LICENSEE ABBREVIATION:
CRITXX: PLANT CRITICALITY DATE
SD: PLANT INDEFINATELY SHUT DOWN

ACCESS	E DATE	SEQ	ACTUAL OCCURRENCE	PLANT	DOC	SY	COMPXX	O	D	E	I	AGEX	SC	RATE	T	V	AE	OPR	CRITXX	S
32429	690313	MSLB	LOOP ISOLAT. VALVES FAILED TO SHUT	IND.POINT1	3	CB	VALVEX	G	T	Y	N	2415	75	265	P	B	UE	CEC	620802	*
36147	690715	LOOP	REACTOR TRIP WITH LOSS OF OFFSITE POWER	HAD.NECK	213	EB	CKTBRK	E	O	Y	Y	752	28	575	P	W	SW	CYA	670724	
39024	720125	LOOP	LOSS OF OFFSITE POWER	BG ROCK PT	155	EA	CKTBRK	E	O	N	Y	3406	39	72	B	G	BX	CPC	620927	
39380	711208	ECIT	SAFETY VALVE OPERATION AFTER LOFW	DRESDEN 3	249	CC	INSTRU	E	O	N	Y	312	36	794	B	G	SL	CWE	710131	
44751	700427	LOFW	3 OF 4 STEAM DRUM SCRAM SENSORS FAIL	DRESDEN 1	010	IC	INSTRU	U	T	N	N	3844	36	200	B	G	BX	CWE	591015	
47814	700505	ECIT	DEPRESSURIZATION INCIDENT	DRESDEN 2	237	CC	INSTRU	E	O	N	Y	150	36	794	B	G	SL	CWE	700107	
59484	710112	LOCA	SUMP ISO. VALVES CLOSED	PT.BEACH 1	266	SF	VALVEX	E	T	N	N	71	28	497	P	W	BX	WMP	701102	
60227	701204	MSLB	FAILURE OF SEVERAL MSIV'S TO CLOSE	DRESDEN 2	237	CC	VALVEX	E	T	N	N	331	59	794	B	G	SL	CWE	700107	
61043	710120	LOOP	LOSS OF OFFSITE POWER	LACROSSE	409	EA	RELAYX	G	O	Y	Y	1289	39	50	B	A	SL	DLP	670711	
61434	700717	LOOP	LOSS OF OFFSITE POWER	HUMBDLTBAY	133	EA	INSTRU	E	O	Y	Y	2708	21	65	B	G	BX	PGE	630216	*
61565	710902	LOOP	LOOP AND FAILURE OF A DIESEL GENERATOR TO LOAD	PALISADES	255	EA	RELAYX	U	O	N	Y	101	22	805	P	C	BX	CPC	710524	
63129	710324	LOOP	LOSS OF OFFSITE POWER	LACROSSE	409	EA	CKTBRK	E	O	N	Y	1352	18	50	B	A	SL	DLP	670711	
63144	710308	LOOP	FAILURE OF BOTH DIESEL GENER. DURING TESTING	ROBINSON 2	261	EE	ENGINE	E	T	N	N	169	29	700	P	W	EX	CPL	700920	
64600	701226	LOOP	SHUTDOWN OF BUCHANAN STATION	IND.POINT1	3	EA	RELAYX	U	O	N	Y	3068	32	265	P	B	UE	CEC	620802	*
65757	710205	LOOP	LOSS OF OFFSITE POWER	PT.BEACH 1	266	EA	CKTBRK	G	O	N	Y	95	28	497	P	W	BX	WMP	701102	
65757	710416	LOCA	FAILURE OF CONTAINMENT SUMP ISO VALVES	PT.BEACH 1	266	SF	VALVEX	C	T	N	N	165	35	497	P	W	BX	WMP	701102	
65969	710908	LOCA	OPEN ELECTROMATIC RELIEF VALVE	PALISADES	255	CB	VALVEX	G	O	Y	Y	107	49	805	P	C	BX	CPC	710524	
66996	711010	LOCA	TRANSIENT AND BLOWDOWN	MILLSTONE1	245	CC	VALVEX	E	O	N	Y	349	27	660	B	G	EX	NNE	701026	
71694	720517	LOOP	LOSS OF OFFSITE POWER	PALISADES	255	EB	RELAYX	G	T	N	Y	359	32	805	P	C	BX	CPC	710524	
73655	720720	LOOP	LOSS OF OFFSITE POWER	IND.POINT1	3	EA	ELECON	E	O	N	Y	3640	32	265	P	B	UE	CEC	620802	*
74242	711231	ECIT	HIGH COOLANT LEVEL	NINEMIPT1	220	CC	VESSEL	E	O	Y	Y	847	36	620	B	G	UX	NMP	690905	
75074	720817	LOOP	LOSS OF LOAD	LACROSSE	407	EA	RELAYX	C	O	Y	Y	1863	39	50	B	A	SL	DPL	670711	
77916	721229	LOCA	MALFUNCTION OF SEVERAL VALVES	OYSTER CRK	219	CH	VALVEX	E	O	Y	Y	1334	37	650	B	G	RB	JCP	690503	
78418	730202	LOCA	VALVE FAILURE TO OPEN DURING TESTING	MA.YANKEE	309	SF	VALVEX	E	T	N	N	102	34	825	P	C	SW	MAY	721023	
79565	721201	LOOP	LOSS OF NORMAL STATION POWER	VT.YANKEE	271	EB	TRANSF	E	O	N	Y	252	32	514	B	G	EX	VYC	720324	
80138	720610	LOOP	FLOODING OF TURBINE BUILDING	QUAD-CTES1	254	CF	PUMPXX	G	O	Y	N	236	34	789	B	G	SL	CWE	711018	
81523	730618	LOFW	FAILURE OF AFW PUMPS TO AUTO-START	TKY.POINT4	251	SF	INSTRU	B	O	Y	N	7	29	693	P	W	BX	FPL	730611	

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Table 3.1 (continued)

82198	730704	LOOP	REACTOR/TURBINE TRIP DURING TEST	TKY.POINT3	250	EB	INSTRU	E	O	N	Y	257	39	693	P	W	BX	FPL	721020	
83833	730908	LOOP	LOSS OF OFFSITE POWER	OYSTER CRK	219	EB	RELAYX	D	O	Y	Y	1589	37	650	B	G	BR	JCP	690503	
85370	731021	LOOP	LOOP,EXCESSIVE RCS COOLDOWN,SFTY INJ.&INS BUS	GINNA	244	EA	ELECON	E	O	N	Y	1443	28	470	P	W	GX	RGE	691108	
85566	731119	LOOP	LOSS OF A.C. POWER CAUSE HPCI/RCIC TO FAIL	BRN.FERRY1	259	SF	RELAYX	B	T	N	Y	65	25	1065	B	G	UX	TVA	730817	
85738	731119	LOFW	RCIC/HPCI FAILS DURING TESTING	BRN.FERRY1	259	SF	VALVEX	B	T	N	Y	65	25	1065	B	G	UX	TVA	730817	
86990	731121	LOOP	WORKER BUMPS RELAY CAUSING LOOP	NINEMIPT1	220	EA	RELAYX	B	O	Y	Y	7072	39	620	B	G	BX	CPC	620927	
88451	740119	LOOP	LOSS OF OFFSITE POWER	HAD.NECK	213	EA	INSTRU	E	O	N	Y	2401	18	575	P	W	SW	CYA	670624	
89153	740221	MSLB	OPEN RWST ISOLATION VALVES	PRAIRIEIS1	282	SF	VALVEX	E	T	Y	N	82	82	530	P	W	PX	NSP	731201	
89205	731130	LRTR	FAILED RCP SHAFT AT 92% POWER	SURRY 1	280	CB	PUMPXX	E	O	N	Y	517	30	822	P	W	SW	VEP	720701	
89252	740217	LOOP	FAILURE OF DIESEL TO START/LOAD;2 AFW PMPS OUT	ZION 2	304	EB	GENERA	E	T	N	N	55	44	1040	P	W	SL	CWE	731224	
90421	740407	LOFW	INOPERABLE AFW PUMPS DURING PLANT SHUTDOWN	PT.BEACH 1	266	SF	FILTER	D	O	N	N	1252	16	497	P	W	BX	WMP	701102	
91676	740508	LOFW	FAILURE OF 3 AUX FWDTR PMPS TO START AT TEST	TKY.POINT3	250	SF	PUMPXX	E	T	Y	N	565	16	693	P	W	BX	FPL	721020	
93553	741208	LOOP	TWO DIESEL GENERATORS MALFUNCTION	HATCH 1	321	EE	ENGINE	Z	T	N	N	87	51	786	B	G	SS	GPC	740912	
93702	740425	LOOP	REACTOR TRIP WITH LOSS OF OFFSITE POWER	TKY.POINT4	251	EB	RELAYX	E	O	N	Y	318	32	693	P	W	BX	FPL	730611	
95040	740823	LOFW	HPCI INJECTION VALVE AND RCIC FAIL	BRN.FERRY2	260	SF	VALVEX	B	T	N	N	33	31	1065	B	G	UX	TVA	740720	
97107	741022	MSLB	BIT AUTO INJECTION FAILURE	ZION 2	304	SF	INSTRU	E	O	Y	N	302	36	1040	P	W	SL	CWE	731224	
97578	741017	LOOP	LOSS OF OFFSITE POWER DURING TESTING	PALISADES	255	EB	RELAYX	G	T	Y	Y	1242	33	805	P	C	BX	CPC	710524	
97779	741124	RCPT	FAILURE OF RPS TO SEE RCP TRIPS	ARKANSAS 1	313	IA	RELAYX	E	T	Y	Y	110	59	850	P	B	BX	APL	740806	
100415	750225	LOFW	ALL DRYWELL HIGH PRESSURE SWITCHES ISOLATED	FITZPATRIK	333	IA	INSTRU	E	T	Y	N	100	34	821	B	G	SW	PNY	741117	
101078	750318	LOOP	DIESEL GENERATOR FIRE	FITZPATRIK	333	EE	ENGINE	E	O	N	N	110	66	821	B	G	SW	PNY	741117	
101444	750322	LOFW	CABLE TRAY FIRE CAUSED EXTENSIVE DAMAGE	BRN.FERRY1	259	SF	ELECON	E	O	Y	Y	582	04	1065	B	G	UX	TVA	730817	
102146	750320	LOOP	LOSS OF OFFSITE POWER	BRUNSWICK2	324	EB	ELECON	G	O	Y	Y	6	39	821	B	G	UE	CPL	750320	
103002	750429	LOFW	MULTIPLE VALVE FAILURES & RCIC INOPERABLE	BRUNSWICK2	324	CC	VALVEX	E	O	Y	N	40	26	821	B	G	UE	CPL	750320	
103077	750501	LOCA	RCP SEAL FAILURE	ROBINSON 2	261	CB	PUMPXX	E	O	N	Y	1684	26	700	P	W	EX	CPL	700920	
103111	750419	LOOP	CONDENSER EMERG. DISCHARGE VLVS FAIL TO OPEN	OCONEE 3	287	WA	CKTBRK	G	T	Y	N	226	40	887	P	B	UX	DPC	740905	
103207	750525	LOOP	BREAKER & RELAY FAILURE DURING TEST	TKY.POINT4	251	EB	RELAYX	G	T	N	N	713	39	693	P	W	BX	FPL	730611	
103892	750613	LOCA	STUCK OPEN PORV	OCONEE 3	287	CB	VALVEX	E	O	Y	Y	281	36	887	P	B	UX	DPC	740905	
104087	750619	LOCA	CLOSED SI TANK ISOLATION VALVES	MA.YANKEE	309	SF	VALVEX	C	T	Y	N	969	74	825	P	C	SW	MAY	721023	
104379	750627	EQUK	EARTHQUAKE OCCURS	HUMBDLTBAY	133	XX	XXXXXX	G	O	N	N	4513	46	65	B	G	BX	PGE	630216	*
104817	750729	INAA	ALL ADS VALVES OPEN INADVERTENTLY	HATCH 1	321	SF	VALVEX	E	T	Y	Y	321	33	786	B	G	SS	GPC	740912	
105540	750817	LOCA	LOW FLOW FEEDWATER LINE SEVERED AT 6X4 REDUCER	QUAD-CTES2	265	CH	PIPEXX	C	O	N	Y	1208	38	789	B	G	SL	CWE	720426	
106333	750909	LOFW	HPCI FOUND INOPERABLE	QUAD-CTES2	265	SF	PUMPXX	E	T	N	N	904	31	789	B	G	SL	CWE	730310	
106616	750913	LOOP	LOSS OF OFFSITE PWR & RELF.VALV STKS OPN	PILGRIM 1	293	EB	CKTBRK	D	O	N	Y	1184	30	655	B	G	BX	BEC	720616	
108078	751105	LOFW	INOPERABLE AFW PUMPS DURING PLANT STARTUP	KEWAUNEE	305	SF	FILTER	C	O	N	N	608	16	535	P	W	FP	WPS	740307	
108869	751220	LOOP	TWO DIESELS FAIL TO START	HATCH 1	321	EE	ENGINE	G	T	N	N	464	44	786	B	G	SS	GPC	740912	
109295	751219	LOCA	FROZEN BWST LEVEL INPULSE LINES WHILE OPRTING	OCONEE 1	269	SF	INSTRU	E	O	N	N	974	48	887	P	B	UX	DPC	730419	
112309	760308	LOOP	GAS TURBINE BECOMES INOPERABLE	MILLSTONE1	245	SF	ENGINE	E	T	N	N	1957	54	660	B	G	EX	NNE	701026	
112310	760315	LOOP	GAS TURBINE FAILS TO ACHIEVE RATED SPEED	MILLSTONE1	245	SF	ENGINE	E	T	N	N	1966	54	660	B	G	EX	NNE	701026	
115870	760706	LOCA	IMPROPER INSULATION	VT.YANKEE	271	SF	VALVEX	G	T	N	N	1565	28	514	B	G	EX	VYC	720324	
115875	760626	LOOP	LOSS OF OFFSITE POWER DURING REFUELING	HAD.NECK	213	EB	RELAYX	H	O	Y	Y	3169	29	575	P	W	SW	CYA	670724	
116212	760720	LOOP	APPARENT LOOP & FAILURE OF SAFETY RELATED COMP	MILLSTONE2	336	EB	RELAYX	E	O	Y	Y	277	20	870	P	C	BX	NNE	751017	
116780	760810	LOOP	GAS TURBINE FAILS DURING PLANT TRIP	MILLSTONE1	245	SF	ENGINE	E	O	N	Y	2153	28	660	B	G	EX	NNE	701026	
117944	760810	LOOP	REACTOR TRIP WITH LOOP & DIESEL GENS.RUNNING	MILLSTONE2	336	EA	ELECON	E	O	N	Y	298	32	870	P	C	BX	NNE	751017	
120207	761028	MSLB	FAILURE OF RWST-CHARGING PUMP SUCTION VALVES	TROJAN	344	SF	VALVEX	G	O	Y	N	318	72	1130	P	W	BX	PGE	751215	

Table 3.1 (continued)

120293	761111	LOOP	PLANT SERVICE WATER STRAINERS PLUGGED	HATCH 1	321	WA	FILTER	E	O	N	N	791	30	786	B	G	SS	GPC	740912	
120439	761101	LOFW	TWO ELECTROMATIC RV FAILURES	QUAD-CTES1	254	SF	VALVEX	E	T	N	N	1841	33	789	B	G	SL	CWE	711018	
120443	761101	LOFW	TWO ELECTROMATIC RV FAILURES	QUAD-CTES2	265	SF	VALVEX	C	T	N	N	1650	28	789	B	G	SL	CWE	720426	
120995	761111	LOCA	VALVES FAIL TO OPEN FOR DECAY HEAT SYSTEM	RANCHOSECO	312	SF	VALVEX	G	T	N	N	787	35	918	P	B	BX	SMU	740916	
121533	770104	LOOP	TWO DIESEL GENERATORS TRIP	BRUNSWICK1	325	EE	ENGINE	E	T	N	N	87	51	821	B	G	UE	CPL	761008	
122366	770110	MSLB	SENSING LINES FROZEN	ARKANSAS 1	313	IB	INSTRU	E	O	N	N	888	73	850	P	B	BX	APL	740806	
123118	770218	LOFW	BOTH AFW PUMPS UNAVAILABLE	RANCHOSECO	312	SF	PUMPXX	E	T	Y	N	886	36	918	P	B	BX	SMU	740916	
123150	770303	MSLB	50% OPEN ATMOSPHERIC DUMP VALVES	CRYSTALRV3	302	IF	GENERA	E	O	N	Y	48	29	825	P	B	GX	FPC	770114	
124201	770322	LOOP	DIESEL GENERATOR FIELD FAILS TO FLASH	DRESDEN 3	249	EE	GENERA	E	T	N	N	2273	66	794	B	G	SL	CWE	710131	
124222	770408	LOFW	SIX MAIN STEAM RELIEF VALVES FAIL TO LIFT	D.ARNOLD	331	SF	VALVEX	G	T	N	N	1110	28	538	B	G	BX	IEL	740323	
124920	770416	MSLB	STEAM GENERATOR OVERFILL	CRYSTALRV3	302	HH	INSTRU	G	T	N	Y	92	58	825	P	B	GX	FPC	770114	
125106	770506	LOCA	FAILURE TO CLEAR OVERPRESSURE DURING HEATUP	SALEM 1	272	SF	PUMPXX	C	O	Y	N	146	55	1090	P	W	UX	PEG	761211	
125563	770516	LOOP	REACTOR TRIP WITH LOSS OF OFFSITE POWER	ST.LUCIE 1	335	EA	XXXXXX	G	O	N	Y	389	34	802	P	C	EX	FPL	760422	
127010	770714	LOOP	FAILURE OF TWO DIESEL GENERATORS	DRESDEN 3	249	EE	ENGINE	E	T	N	N	2160	66	794	B	G	SL	CWE	710131	
127384	770712	LOCA	DUMMY SIGNALS INSTALLED ON INSTRUMENTENTATION	ZION 2	304	IA	INSTRU	G	T	Y	Y	1296	29	1040	P	W	SL	CWE	731224	
128569	770715	LOCA	SAFETY RELIEF VALVE FAILS TO RESET	BRUNSWICK2	324	CA	VALVEX	E	O	N	Y	281	27	821	B	G	UE	CPL	750320	
128906	770831	LOFW	LOSS OF NO-BREAK-POWER AND FEEDWATER CONTROL	COOPER	298	SF	GENERA	E	O	N	Y	1287	19	778	B	G	BR	NPP	740221	
128935	770822	LOOP	MOMENTARY LOSS OF OFFSITE POWER	FTCALHOUN1	285	EA	CKTBRK	E	O	N	Y	1477	32	457	P	C	GH	DPP	730806	
130111	770901	LOOP	REACTOR TRIP & LOSS OF OFFSITE POWER	COOK 1	315	EA	RELAYX	E	O	N	Y	957	39	1054	P	W	AE	IME	750118	
130119	770924	LOOP	REACTOR TRIP DUE TO LOSS OF OFFSITE POWER	PALISADES	255	EB	CKTBRK	E	O	N	Y	2315	32	805	P	C	BX	CPC	710524	
130788	770924	LOCA	STUCK OPEN PORV	DVS-BESSE1	346	CB	VALVEX	E	O	N	Y	43	29	906	P	B	BX	TEC	770812	
130889	771011	LOCA	FLOODING OF VALVE PIT DURING 0 PWR PHYSIC TST	SURRY 2	281	WB	VALVEX	B	T	Y	N	1928	55	822	P	W	SW	VEP	730307	
131225	770828	LOOP	TWO DIESEL GENERATORS FAIL TO START	PEACHBTOM2	227	EE	ENGINE	G	T	Y	N	1443	51	1065	B	G	GX	PEC	730916	
132155	771129	LOOP	DIESEL GENERATOR TRIPS DURING TESTING	DRESDEN 3	249	EE	ENGINE	E	T	N	N	2493	51	794	B	G	SL	CWE	710131	
132927	771129	LOOP	LOSS OF OFFSITE POWER	DVS-BESSE1	346	EB	XXXXXX	E	O	Y	Y	109	29	906	P	B	BX	TEC	770812	
132942	771209	LOOP	BOTH DIESEL GENERATORS INOPERABLE	PRAIRIEIS1	282	EE	INSTRU	H	T	Y	N	1469	75	530	P	W	PX	NSP	731201	
132943	771125	LOOP	REACTOR TRIP WITH LOSS OF OFFSITE POWER	PALISADES	255	EB	CKTBRK	E	O	N	Y	2377	32	805	P	C	BX	CPC	710524	
132947	771202	LOOP	DIESEL GENERATOR FAILS TO START	DRESDEN 2	237	EE	ENGINE	H	T	N	N	2890	66	794	B	G	SL	CWE	700107	
132958	771211	LOOP	REACTOR TRIP WITH LOSS OF OFFSITE POWER	PALISADES	255	EB	CKTBRK	E	O	N	Y	2393	32	805	P	C	BX	CPC	710524	
132979	770515	LOOP	FUEL SUPPLY VALVES FOUND SHUT DURING INSPECT.	MILLSTONE2	336	EE	ENGINE	G	O	Y	N	576	49	870	P	C	BX	NNE	751017	
133004	770613	LOOP	3/4 DIESELS INOPERABLE	PEACHBTOM3	278	EE	ENGINE	E	T	Y	N	1041	54	1065	B	G	BX	PEC	740807	
133706	771211	LOFW	AUX. FEEDWATER PUMPS INOPERABLE DURING TEST	DVS-BESSE1	346	SF	PUMPXX	G	T	N	N	121	16	906	P	B	BX	TEC	770812	
135006	770916	LOOP	LOSS OF OFFSITE POWER	FARLEY 1	348	EB	RELAYX	C	O	Y	Y	38	32	829	P	W	BX	APC	770809	
135077	771026	MSLB	THERMO WELL COUPLING FAILED AFTER SAFETY INJ.	ROBINSON 2	261	SF	ACCUMU	G	O	N	N	2593	72	700	P	W	EX	CPL	700920	
135079	771123	LOCA	SI PUMP BREAKERS INCORRECTLY RACKED OUT	ROBINSON 2	261	SF	CKTBRK	G	O	Y	N	2621	54	700	P	W	EX	CPL	700920	
135932	780206	LOOP	LOSS OF OFFSITE POWER	PILGRIM 1	293	EA	ELECON	E	O	N	Y	2061	42	655	B	G	BX	BEC	720616	
137305	780325	LOFW	LOW-LOW WATER LEVEL IN ONE STEAM GENERATOR	FARLEY 1	348	SH	VALVEX	E	O	Y	N	228	19	829	P	W	BX	APC	770809	
137335	780404	LOFW	IC INADVERNTLY RENDERED INOPERABLE	DRESDEN 2	237	SF	XXXXXX	E	O	Y	N	3034	58	784	B	G	SL	CWE	710131	
137384	780318	LOCA	RELAY FAILURE	TMI 1	289	SF	PUMPXX	B	T	N	N	1382	56	819	P	B	GX	MEC	740605	
137543	780413	LOOP	LOSS OF OFFSITE POWER WHILE SHUTDOWN	CALCLIFFS1	317	EA	CKTBRK	G	O	N	Y	1284	23	845	P	C	BX	BGE	741007	
137918	780423	MSLB	MULTIPLE STUCK-OPEN RELIEF VALVES	TMI 2	320	HB	VALVEX	E	O	N	Y	26	22	906	P	B	BR	MEC	780328	*
138830	780320	LOFW	FAILURE OF NNI & STEAM GENERATOR DRYOUT	RANCHOSECO	312	IE	INSTRU	E	O	Y	Y	1281	06	918	P	B	BX	SMU	740916	
139565	780514	LOOP	LOSS OF OFFSITE POWER DURING REFUELING	ST.LUCIE 1	335	EA	CKTBRK	H	O	Y	Y	752	23	802	P	C	EX	FPL	760422	
139573	780615	LOOP	UNAVAILABILITY OF BOTH DIESEL GENERATORS	COOK 2	316	EE	ENGINE	E	O	Y	N	97	63	1100	P	W	AE	IME	780310	

Table 3.1 (continued)

140140	780806	LOOP	LOSS OF OFFSITE POWER	PILGRIM 1	293	EA	ELECON	E	O	N	Y	2242	42	655	B	G	BX	BEC	720616	
140162	780824	LOOP	DIESEL GENERATOR FAILS TO START	DRESDEN 2	237	EE	ENGINE	E	T	N	N	2761	66	794	B	G	SL	CWE	710131	
140335	780728	LOOP	LOOP AND DIESEL GENERATOR FAILURE	BVRVALLEY1	334	EB	TRANSF	E	O	N	Y	809	23	852	P	W	SW	DLC	760510	
140691	780905	LOOP	BOTH DIESEL GENERATORS OUT OF SERVICE	BVRVALLEY1	334	EE	CKTBRK	G	T	N	N	848	76	852	P	W	SW	DLC	760510	
140693	780912	LOOP	BOTH DIESEL GENERATORS OUT OF SERVICE	BVRVALLEY1	334	EE	CKTBRK	G	T	N	N	855	75	852	P	W	SW	DLC	760510	
141097	780329	LOCA	STUCK OPEN PORV	TMI 2	320	EB	GENERA	B	O	N	Y	1	30	906	P	B	BR	MEC	780328	*
141455	781004	LOOP	BOTH DIESEL GENERATORS OUT OF SERVICE	RANCHOSECO	312	EE	ENGINE	E	O	N	N	1479	65	918	P	B	BX	SMU	740916	
141523	781017	LOCA	INOPERABLE LPSI PUMPS	CALCLIFFS2	318	SF	PUMPXX	G	O	N	N	686	67	845	P	C	BX	BGE	761130	
141706	781024	LOOP	LOSS OF 1 DG WHILE 2ND OUT OF SERVICE	RANCHOSECO	312	EE	ENGINE	E	O	N	N	1499	56	918	P	B	BX	SMU	740916	
142329	781126	MSLB	HEAT TRACING CIRCUIT FAILURE	IND.POINT2	247	SF	PIPEXX	G	O	N	N	2014	72	873	P	W	UE	CEC	730522	
142462	781127	LOCA	LOSS OF VITAL INST. BUS-REACTOR TRIP	SALEM 1	272	EB	GENERA	E	O	Y	Y	716	23	1090	P	W	UX	PEG	761211	
143219	770713	LOOP	LOSS OF OFFSITE POWER	IND.POINT3	286	EA	ELECON	G	O	N	Y	463	33	965	P	W	UE	PNY	760406	
143255	770730	LOOP	DIESEL GENERATORS FAILED TO START AT TEST	SALEM 1	272	EE	ENGINE	G	T	N	N	231	67	1090	P	W	UX	PEG	761211	
143296	771020	LOCA	INADVERTENT VALVE CLOSING DURING TEST	MA.YANKEE	309	SF	VALVEX	E	T	Y	N	1823	68	825	P	C	SW	MAY	721023	
143533	771010	LOOP	DIESEL GENERATOR LOAD CYCLES	BRUNSWICK1	325	EE	ENGINE	E	T	N	N	367	66	821	B	G	UE	CPL	761008	
144187	771210	LOOP	DIESEL GENERATOR FOUND INOPERABLE	MILLSTONE1	245	EE	ENGINE	E	T	N	N	2616	50	660	B	G	EX	NNE	701026	
145209	781220	LOCA	TWO STUCK OPEN PROV'S DURING COLD SHUTDOWN	FTCALHOUN1	285	CJ	VALVEX	G	O	Y	Y	1962	37	457	P	C	GH	DPP	730806	
146540	790110	LOOP	ONE DG FAILED WHILE 2ND OUT DUE TO MAINTENANCE	KEWAUNEE	305	EE	ENGINE	E	O	N	N	1770	68	535	P	W	FP	WPS	740307	
146744	790112	LOFW	LOSS OF VITAL BUS WHILE AT POWER	DVS-BESSE1	346	EB	GENERA	E	O	Y	N	518	30	906	P	B	BX	TEC	770812	
147223	790106	MSLB	TURBINE TRIP AND STUCK FW VALVE	CRYSTALRV3	302	HH	VALVEX	E	O	N	N	722	64	825	P	B	GX	FPC	770114	
147383	790223	LOOP	TWO DIESEL GENERATORS NOT AVAILABLE (TWICE)	COOK 1	315	EE	ENGINE	E	O	Y	N	1497	64	1054	P	W	AE	IME	750118	
147399	790221	LOOP	BOTH DIESEL GENERATORS UNAVAILABLE	KEWAUNEE	305	EE	ENGINE	E	T	N	N	1812	59	535	P	W	FP	WPS	740307	
147400	790219	MSLB	MAIN STEAM STOP VALVES FAILED TO CLOSE AT TEST	PT.BEACH 2	301	HB	VALVEX	E	T	N	N	3031	54	497	P	W	BX	WMP	720530	
148764	790118	MSLB	STUCK OPEN STEAM DUMP VALVES	BVRVALLEY1	334	HB	VALVEX	E	O	Y	Y	983	29	852	P	W	SW	DLC	760510	
148892	790222	LOOP	UNAVAILABILITY OF TWO DIESEL GENERATORS	FARLEY 1	348	EB	INSTRU	E	O	N	N	562	50	829	P	W	BX	APC	770809	
149230	790321	LOOP	BOTH EMERGENCY SERVICE WATER SYSTEM OUT	D.ARNOLD	311	WG	FILTER	E	T	N	N	1824	45	538	B	G	BX	IEL	740323	
149250	790414	MSLB	MSIVS FAILED TO CLOSE DURING TEST	TROJAN	344	HB	VALVEX	G	T	N	N	1216	55	1130	P	W	BX	PGE	751215	
149450	790502	LOFW	LOSS OF FEEDWATER FLOW	OYSTER CRK	219	CJ	VALVEX	E	O	Y	Y	3651	16	650	B	G	BR	JCP	690503	
149961	790603	LOFW	HPCI FAILS TO START GIVEN LOFW	HATCH 1	366	SF	PUMPXX	E	O	Y	Y	334	19	784	B	G	SS	GPC	780704	
149962	790505	LOOP	DIESEL GENERATOR UNABLE TO CARRY LOAD	HATCH 1	321	EE	GENERA	G	T	N	N	1535	77	786	B	G	SS	GPC	740912	
150051	790612	LOOP	FAILURE OF TWO DIESEL GENERATORS	DRESDEN 2	237	EE	ENGINE	E	T	N	N	3473	51	794	B	G	SL	CWE	700107	
150271	790603	LOFW	BOTH RHR SERVICE WATER PMPS NOT OPERABLE	BRUNSWICK2	324	SF	PUMPXX	E	T	Y	N	1536	46	821	B	G	UE	CPL	750320	
150499	790628	LOFW	RCIC AND HPCI ISOLATE FOLLOWING REACTOR SCRAM	HATCH 2	366	SF	INSTRU	G	T	N	N	359	36	784	B	G	SS	GPC	780704	
150742	790622	LOFW	MAIN STACK SAMPLING SYSTEM LOST	PEACHBTOM3	278	SF	CKTBRK	E	O	N	N	2175	50	1065	B	G	BX	PEC	740807	
150882	790606	LOOP	BOTH DG'S TRIPPED DURING TEST	CRYSTALRV3	302	EE	ENGINE	G	T	Y	N	873	30	825	P	B	GX	FPC	770114	
150943	790727	LOOP	LOSS OF OFFSITE POWER	PILGRIM 1	293	EA	ELECON	E	O	N	Y	2597	42	655	B	G	BX	BEC	720616	
151433	790911	LOCA	INCORRECT RHR SERVICE PUMP BREAKER RACKED OUT	BRUNSWICK2	324	CF	PUMPXX	E	T	Y	N	1636	70	821	B	G	UE	CPL	750320	
151635	790828	LOOP	LOSS OF OFFSITE POWER	PILGRIM 1	293	EA	CKTBRK	E	O	N	Y	2629	42	655	B	G	BX	BEC	720616	
152183	790813	LOCA	OPEN PWR OPERATED RELIEF VALVE + ISO.VALVE	HAD.NECK	213	HB	VALVEX	E	O	N	Y	4433	36	575	P	W	SW	CYA	670724	
152187	790903	LOOP	SWITCHYARD LOCKOUT DUE TO CABLE DROP AT STORM	ST.LUCIE 1	335	EE	ENGINE	G	O	N	Y	1229	25	802	P	C	EX	FPL	760422	
152563	791002	SGTR	STEAM GENERATOR TUBE BREAK	PRAIRIEIS1	282	HB	HTEXCH	E	O	N	Y	2131	27	530	P	W	PX	NSP	731201	
152638	791017	LOOP	UNAVAIL OF 1 AFW PUMP AND 1 DIESEL GENERATOR	COOK 2	316	SF	PUMPXX	E	O	Y	N	586	66	1100	P	W	AE	IME	780310	
152835	790731	LOOP	OVR VOLTG PROT TRIP FOUND WHILE TRBLE SHTG	CALCLIFFS1	317	IB	INSTRU	E	O	N	N	1758	59	845	P	C	BX	BGE	741007	
152951	791015	LOOP	REACTOR TRIP WITH LOSS OF OFFSITE POWER	DVS-BESSE1	346	IC	CKTBRK	E	O	N	Y	794	36	906	P	B	BX	TEC	770812	

Table 3.1 (continued)

153003	791024	LOCA	FAILURE TO PROPERLY POSITION VALVES AFTER TEST	OCONEE 2	270	SH	VALVEX	E	O	Y	N	2173	43	887	P	B	UX	DPC	731111	
153164	790328	LOFW	LOSS OF FEEDWATER & OPEN PORV	TMI 2	320	CJ	VALVEX	E	O	Y	Y	365	00	906	P	B	BR	MEC	780328	*
153167	790926	LOOP	LOSS OF STANDBY POWER SOURCE DURING PWR OPRT	OCONEE 1	269	EE	ENGINE	E	O	N	N	2351	52	887	P	B	UX	DPC	730419	
153167	790926	LOOP	LOSS OF STANDBY POWER SOURCE DURING PWR OPRT	OCONEE 2	270	EE	ENGINE	E	O	N	N	2145	52	887	P	B	UX	DPC	731111	
153333	791115	LOFW	AFW UNAVAIL DUE TO MAINTENANCE AND INSPECTION	COOK 1	315	SF	PUMPXX	G	T	Y	N	1762	40	1054	P	W	AE	IME	750118	
153338	791101	LOOP	INCORRECT DIESEL GENERATOR MAINT. WHILE REFUEL	COOK 2	316	EE	ENGINE	H	O	Y	N	601	67	1100	P	W	AE	IME	780310	
153686	791127	LOOP	DG AND CHARGING PMP SUCT VALVE UNAVAILABLE	BVRVALLEY1	334	EE	ENGINE	E	O	Y	N	1296	71	852	P	W	SW	DLC	760510	
153810	791120	LOFW	RCIC TURBINE TRIP WITH HPCI UNAVAILABLE	BRUNSWICK1	325	CE	MECFUN	E	O	N	Y	1139	25	821	B	G	UE	CPL	761008	
154286	791128	LOCA	ONE PMP FAILED + 1 DEGRADED IN CLD SHTDN	SALEM 1	272	SF	PUMPXX	G	O	N	N	1082	35	1090	P	W	UX	PEG	761211	
154639	791209	LOOP	BOTH DIESEL GENERATORS INOPERABLE	DVS-BESSE1	346	EE	ENGINE	G	T	N	N	849	73	906	P	B	BX	TEC	770812	

ABBREVIATIONS:

ACCESS: 6 DIGIT NSIC ACCESSION NUMBER
E DATE: EVENT DATE
SEQ: SEQUENCE OF INTEREST FOR THE EVENT
    ECIT - EXCESSIVE COOLANT INVENTORY
    EQUK - EARTHQUAKE
    INAA - INADVERTANT ADS ACTUATION
    LOFW - LOSS OF FEEDWATER
    LOOP - LOSS OF OFFSITE POWER
    LOCA - LOSS OF COOLANT ACCIDENT
    LRTR - LOCKED ROTOR ACCIDENT
    MSLB - MAIN STEAM LINE BREAK
    RCPT - REACTOR COOLANT PUMP TRIP
    SGTR - STEAM GENERATOR TUBE RUPTURE
ACTUAL OCCURRENCE: DESCRIPTION OF EVENT
PLANT NAME: NAME OF PLANT AND UNIT NUMBER
DOC: PLANT DOCKET NUMBER
SY:SYSTEM ABBREVIATION:

STANDARD GENERIC CODE	SYSTEM DESCRIPTION
	REACTOR
RA	REACTOR VESSEL INTERNALS
RB	REACTIVITY CONTROL SYSTEMS
RC	REACTOR CORE

Table 3.1 (continued)

REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

CA	REACTOR VESSELS AND APPURTENANCES
CB	COOLANT RECIRCULATION SYSTEMS AND CONTROLS
CC	MAIN STEAM SYSTEMS AND CONTROLS
CD	MAIN STEAM ISOLATION SYSTEMS AND CONTROLS
CE	REACTOR CORE ISOLATION COOLING SYSTEMS AND CONTROLS
CF	RESIDUAL HEAT REMOVAL SYSTEMS AND CONTROLS
CG	REACTOR COOLANT CLEANUP SYSTEMS AND CONTROLS
CH	FEEDWATER SYSTEMS AND CONTROLS
CI	REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS
CJ	OTHER COOLANT SUBSYSTEMS AND THEIR CONTROLS

ENGINEERED SAFETY FEATURES

SA	REACTOR CONTAINMENT SYSTEMS
SB	CONTAINMENT HEAT REMOVAL SYSTEMS AND CONTROLS
SC	CONTAINMENT AIR PURIFICATION AND CLEANUP SYSTEMS AND CONTROLS
SD	CONTAINMENT ISOLATION SYSTEMS AND CONTROLS
SE	CONTAINMENT COMBUSTIBLE GAS CONTROL SYSTEMS AND CONTROLS
SF	EMERGENCY CORE COOLING SYSTEMS AND CONTROLS
SG	CONTROL ROOM HABITABILITY SYSTEMS AND CONTROLS
SH	OTHER ENGINEERED SAFETY FEATURE SYSTEMS AND THEIR CONTROLS

INSTRUMENTATION AND CONTROLS

IA	REACTOR TRIP SYSTEMS
IB	ENGINEERED SAFETY FEATURE INSTRUMENT SYSTEMS
IC	SYSTEMS REQUIRED FOR SAFE SHUTDOWN
ID	SAFETY RELATED DISPLAY INSTRUMENTATION
IE	OTHER INSTRUMENT SYSTEMS REQUIRED FOR SAFETY
IF	OTHER INSTRUMENT SYSTEMS NOT REQUIRED FOR SAFETY

ELECTRIC POWER SYSTEMS

EA	OFFSITE POWER SYSTEMS AND CONTROLS
EB	AC ONSITE POWER SYSTEMS AND CONTROLS
EC	DC ONSITE POWER SYSTEMS AND CONTROLS
ED	ONSITE POWER SYSTEMS AND CONTROLS (COMPOSITE AC AND DC)
EE	EMERGENCY GENERATOR SYSTEMS AND CONTROLS
EF	EMERGENCY LIGHTING SYSTEMS AND CONTROLS
EG	OTHER ELECTRIC POWER SYSTEMS AND CONTROLS

Table 3.1 (continued)

FUEL STORAGE AND HANDLING SYSTEMS

FA	NEW FUEL STORAGE FACILITIES
FB	SPENT FUEL STORAGE FACILITIES
FC	SPENT FUEL POOL COOLING AND CLEANUP SYSTEMS AND CONTROLS
FD	FUEL HANDLING SYSTEMS

AUXILIARY WATER SYSTEMS

WA	STATION SERVICE WATER SYSTEMS AND CONTROLS
WB	COOLING SYSTEMS FOR REACTOR AUXILIARIES AND CONTROLS
WC	DEMINERALIZED WATER MAKE-UP SYSTEMS AND CONTROLS
WD	POTABLE AND SANITARY WATER SYSTEMS AND CONTROLS
WE	ULTIMATE HEAT SINK FACILITIES
WF	CONDENSATE STORAGE FACILITIES
WG	OTHER AUXILIARY WATER SYSTEMS AND THEIR CONTROLS

AUXILIARY PROCESS SYSTEMS

PA	COMPRESSED AIR SYSTEMS AND CONTROLS
PB	PROCESS SAMPLING SYSTEMS
PC	CHEMICAL, VOLUME CONTROL AND LIQUID POISON SYSTEMS AND CONTROLS
PD	FAILED FUEL DETECTION SYSTEMS
PE	OTHER AUXILIARY PROCESS SYSTEMS AND THEIR CONTROLS

OTHER AUXILIARY SYSTEMS

AA	AIR CONDITIONING, HEATING, COOLING AND VENTILATION SYSTEMS AND CONTROLS
AB	FIRE PROTECTION SYSTEMS AND CONTROLS
AC	COMMUNICATION SYSTEMS
AD	OTHER AUXILIARY SYSTEMS AND THEIR CONTROLS

STEAM AND POWER CONVERSION SYSTEMS

HA	TURBINE-GENERATORS AND CONTROLS
HB	MAIN STEAM SUPPLY SYSTEM AND CONTROLS (OTHER THAN CC)
HC	MAIN CONDENSER SYSTEMS AND CONTROLS
HD	TURBINE GLAND SEALING SYSTEMS AND CONTROLS
HE	TURBINE BYPASS SYSTEMS AND CONTROLS
HF	CIRCULATING WATER SYSTEMS AND CONTROLS
HG	CONDENSATE CLEAN-UP SYSTEMS AND CONTROLS
HH	CONDENSATE AND FEEDWATER SYSTEMS AND CONTROLS (OTHER THAN CH)
HI	STEAM GENERATOR BLOWDOWN SYSTEMS AND CONTROLS
HJ	OTHER REATURES OF STEAM AND POWER CONVERSION SYSTEMS (NOT INCLUDED ELSEWHERE)

Table 3.1 (continued)

RADIOACTIVE WASTE MANAGEMENT SYSTEMS

MA LIQUID RADIOACTIVE WASTE MANAGEMENT SYSTEMS
MB GASEOUS RADIOACTIVE WASTE MANAGEMENT SYSTEMS
MC PROCESS AND EFFLUENT RADIOLOGICAL MONITORING SYSTEMS
MD SOLID RADIOACTIVE WASTE MANAGEMENT SYSTEMS

RADIATION PROTECTION SYSTEMS

BA AREA MONITORING SYSTEMS
BB AIRBORNE RADIOACTIVITY MONITORING SYSTEMS

XX OTHER SYSTEMS

ZZ SYSTEM CODE NOT APPLICABLE

COMPXX: SYSTEM COMPONENT CODE:

COMPONENT TYPE (COMPONENT CODE)	COMPONENT TYPE INCLUDES
ACCUMULATORS (ACCUMU)	SCRAM ACCUMULATORS SAFETY INJECTION TANKS SURGE TANKS HOLDUP/STORAGE TANKS
AIR DRYERS (AIRDRY)	
ANNUNCIATOR MODULES (ANNUNC)	ALARMS BELLS BUZZERS CLAXONS HORNS GONGS SIRENS
BATTERIES AND CHARGERS (BATTRY)	CHARGERS DRY CELLS WET CELLS STORAGE CELLS

COMPONENT TYPE (COMPONENT CODE)	COMPONENT TYPE INCLUDES
BLOWERS (BLOWER)	COMPRESSORS GAS CIRCULATORS FANS VENTILATORS
CIRCUIT CLOSERS/INTERRUPTERS (CKTBRK)	CIRCUIT BREAKERS CONTACTORS CONTROLLERS STARTERS SWITCHES (OTHER THAN SENSORS) SWITCHGEAR
CONTROL RODS (CONROD)	POISON CURTAINS
CONTROL ROD DRIVE MECHANISMS (CRDRVE)	
DEMINERALIZERS (DEMINX)	ION EXCHANGERS

Table 3.1 (continued)

ELECTRICAL CONDUCTORS (ELECON)	BUS CABLE WIRE
ENGINES, INTERNAL COMBUSTION (ENGINE)	BUTANE ENGINES DIESEL ENGINES GASOLINE ENGINES NATURAL GAS ENGINES PROPANE ENGINES
FILTERS (FILTER)	STRAINERS SCREENS
FUEL ELEMENTS (FUELXX)	
GENERATORS (GENERA)	INVERTERS
HEATERS, ELECTRIC (HEATER)	HEAT TRACERS
HEAT EXCHANGERS (HTEXCH)	CONDENSERS COOLERS EVAPORATORS REGENERATIVE HEAT EXCHANGERS STEAM GENERATORS FAN COIL UNITS
INSTRUMENTATION AND CONTROLS (INSTRU)	CONTROLLERS SENSORS/DETECTORS/ELEMENTS INDICATORS DIFFERENTIALS INTEGRATORS (TOTALIZERS) POWER SUPPLIES RECORDERS SWITCHES TRANSMITTERS COMPUTATION MODULES
MECHANICAL FUNCTION UNITS (MECFUN)	MECHANICAL CONTROLLERS GOVERNORS GEAR BOXES VARIDRIVES COUPLINGS
MOTORS (MOTORX)	ELECTRIC MOTORS HYDRAULIC MOTORS PNEUMATIC (AIR) MOTORS SERVO MOTORS
PENETRATIONS, PRIMARY CONTAIN. (PENETR)	AIR LOCKS PERSONNEL ACCESS FUEL HANDLING EQUIPMENT ACCESS ELECTRICAL INSTRUMENT LINE PROCESS PIPING
PIPES, FITTINGS (PIPEXX)	
PUMPS (PUMPXX)	
RECOMBINERS (RECOMB)	
RELAYS (RELAYX)	SWITCHGEAR
SHOCK SUPPRESSORS AND SUPPORT (SUPORT)	HANGERS SUPPORTS SWAY BRACES/STABILIZERS SNUBBERS ANTI-VIBRATION DEVICES
TRANSFORMERS (TRANSF)	

Table 3.1 (continued)

TURBINES (TURBIN)	STEAM TURBINES GAS TURBINES HYDRO TURBINES	VESSELS, PRESSURE (VESSEL)	CONTAINMENT VESSELS DRYWELLS PRESSURE SUPPRESSION PRESSURIZERS REACTOR VESSELS
VALVES (VALVEX)	VALVES DAMPERS	OTHER COMPONENTS (XXXXXX)	
VALVE OPERATORS (VALVOP)	EXPLOSIVE, SQUIB	CODES NOT APPLICABLE (ZZZZZZ)	

O: PLANT OPERATING STATUS:

CODE	STATUS
A	(UNDER) CONSTRUCTION
B	PREOPERATIONAL, STARTUP OR POWER ASCENSION TESTS (IN PROGRESS)
C	ROUTINE STARTUP OPERATIONS
D	ROUTINE SHUTDOWN OPERATIONS
E	STEADY STATE OPERATION
F	LOAD CHANGES DURING ROUTINE POWER OPERATION
G	SHUTDOWN (HOT OR COLD) EXCEPT REFUELING
H	REFUELING
U	UNKNOWN
X	OTHER (INCLUDING SPECIAL TESTS, EMERGENCY SHUTDOWN OPERATIONS, ETC.)
Z	ITEM NOT APPLICABLE

D: DISCOVERY METHOD (O-OPERATIONAL EVENT, T-TESTING)
E: HUMAN ERROR INVOLVED (N-NO, Y-YES)
I: TRANSIENT/ACCIDENT INDUCED BY ACTUAL OCCURRENCE (N-NO, Y-YES)
AGEX: PLANT AGE AT THE TIME OF THE EVENT IN DAYS
SC: SIGNIFICANCE CATEGORY
RATE: PLANT ELECTRICAL RATING IN MEGAWATTS ELECTRIC
T: PLANT TYPE (B=BWR, P=PWR)
V: PLANT NSSS VENDOR
  A-ALLIS CHALMERS
  B-BABCOCK AND WILCOX
  C-COMBUSTION ENGINEERING
  G-GENERAL ELECTRIC
  W-WESTINGHOUSE

Table 3.1 (continued)

AE: PLANT ARCHITECT ENGINEER

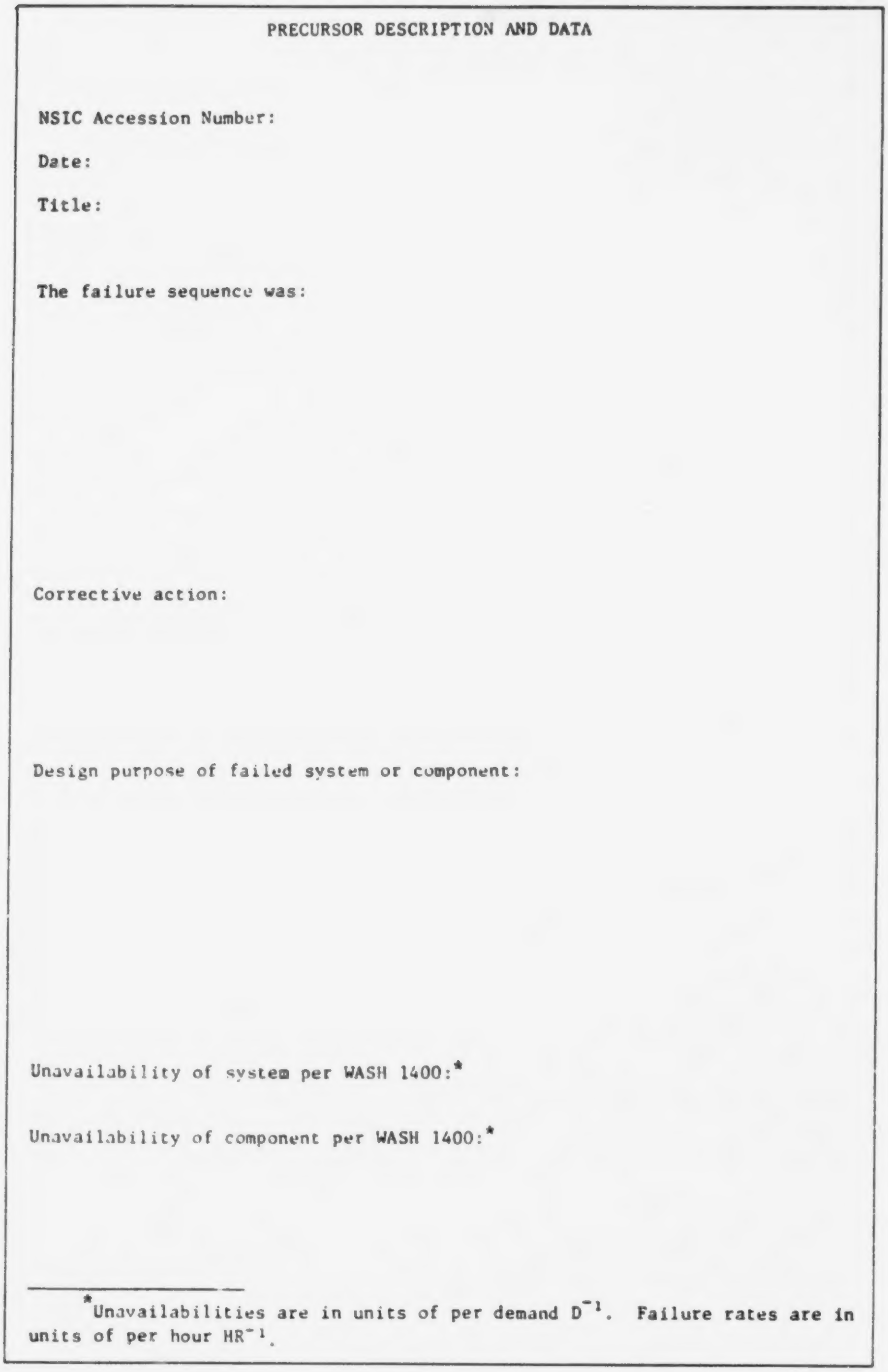
AE-AMERICAN ELECTRIC POWER
BR-BURNS AND ROE
BX-BECHTEL
EX-EBASCO
FP-FLOUR POWER
GH-GIBBS AND HILL
GX-GILBERT
PX-PIONEER
RT-BROWN AND ROOT
SL-SARGENT AND LUNDY
SS-SOUTHERN SERVICES
SW-STONE AND WEBSTER
UE-UNITED ENGINEERS
UX-UTILITY
XX-OTHER

OPR: PLANT LICENSEE ABBREVIATION:

ABBR.	LICENSEE
APC	ALABAMA POWER COMPANY
APL	ARKANSAS POWER AND LIGHT COMPANY
APS	ARIZONA PUBLIC SERVICE COMPANY
BEC	BOSTON ELECTRIC COMPANY
BGE	BALTIMORE GAS AND ELECTRIC COMPANY
CEC	CONSOLIDATED EDISON COMPANY
CEI	CLEVELAND ELECTRIC ILLUMINATING COMPANY
CGE	CINCINNATI GAS AND ELECTRIC COMPANY
CPC	CONSUMERS POWER COMPANY
CPL	CAROLINA POWER AND LIGHT COMPANY
CWE	COMMONWEALTH EDISON COMPANY
CYA	CONNECTICUT YANKEE ATOMIC POWER COMPANY
DLP	DAIRYLAND POWER COOPERATIVE
DLC	DUQUESNE LIGHT COMPANY
DPC	DUKE POWER COMPANY
DPP	OMAHA PUBLIC POWER DISTRICT
FPC	FLORIDA POWER CORPORATION
FPL	FLORIDA POWER AND LIGHT COMPANY
GPC	GEORGIA POWER COMPANY
GSU	GULF STATES UTILITIES
HLP	HOUSTON LIGHTING AND POWER COMPANY
IEL	IOWA ELECTRIC LIGHT AND POWER COMPANY
IME	INDIANA AND MICHIGAN ELECTRIC COMPANY
IPC	ILLINOIS POWER COMPANY
JCP	JERSEY CENTRAL POWER AND LIGHT COMPANY
KGE	KANSAS GAS AND ELECTRIC COMPANY
LIL	LONG ISLAND LIGHTING COMPANY
LPL	LOUISIANA POWER AND LIGHT COMPANY
MEC	METROPOLITAN EDISON COMPANY
MPL	MISSISSIPPI POWER AND LIGHT COMPANY
MYA	MAINE YANKEE ATOMIC POWER COMPANY
NIC	NORTHERN INDIANA PUBLIC SERVICE COMPANY
NMP	NIAGARA MOHAWK POWER CORPORATION
NNE	NORTHEAST NUCLEAR ENERGY COMPANY
NPP	NEBRASKA PUBLIC POWER DISTRICT
NSP	NORTHERN STATES POWER COMPANY
PEC	PHILADELPHIA ELECTRIC COMPANY
PEG	PUBLIC SERVICE ELECTRIC AND GAS COMPANY
PEP	POTOMAC ELECTRIC POWER COMPANY
PGC	PORTLAND GENERAL ELECTRIC COMPANY
PGE	PACIFIC GAS AND ELECTRIC COMPANY
PNY	POWER AUTHORITY OF THE STATE OF NEW YORK
PPL	PENNSYLVANIA POWER AND LIGHT COMPANY
PSC	PUBLIC SERVICE COMPANY OF COLORADO
PSI	PUBLIC SERVICE OF INDIANA
PSN	PUBLIC SERVICE OF NEW HAMPSHIRE
PSO	PUBLIC SERVICE COMPANY OF OKLAHOMA
PSP	PUGET SOUND POWER AND LIGHT COMPANY
RGE	ROCHESTER GAS AND ELECTRIC CORPORATION
SCC	SOUTH CAROLINA ELECTRIC AND GAS COMPANY
SCE	SOUTHERN CALIFORNIA EDISON COMPANY
SMU	SACRAMENTO MUNICIPAL UTILITIES DISTRICT
TEC	TOLEDO EDISON COMPANY
TUG	TEXAS UTILITIES GENERATING COMPANY
TVA	TENNESSEE VALLEY AUTHORITY
UEC	UNION ELECTRIC COMPANY
VEP	VIRGINIA ELECTRIC AND POWER COMPANY
VYC	VERMONT YANKEE NUCLEAR POWER CORPORATION
WEP	WISCONSIN ELECTRIC POWER COMPANY
WMP	WISCONSIN-MICHIGAN POWER COMPANY
WPP	WASHINGTON PUBLIC POWER SUPPLY SYSTEM
WPS	WISCONSIN PUBLIC SERVICE CORPORATION
YAC	YANKEE ATOMIC ELECTRIC COMPANY

CRITXX: PLANT CRITICALITY DATE
SD: PLANT INDEFINATELY SHUT DOWN

ORNL-DWG 82-5604 ETD



PRECURSOR DESCRIPTION AND DATA

NSIC Accession Number:

Date:

Title:

The failure sequence was:

Corrective action:

Design purpose of failed system or component:

Unavailability of system per WASH 1400:*

Unavailability of component per WASH 1400:*

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*Unavailabilities are in units of per demand D^{-1}. Failure rates are in units of per hour HR^{-1}.

Fig. 3.1. Precursor description and data sheet.

2. Categorization of accident sequence precursors sheet (Fig. 3.2) includes selected characteristics of the event and of the plant where the event occurred. These categorizations were used in subsequent analyses.

3. Event tree describing the actual occurrence is based on the event as reported in the LER. Failed equipment is identified and the sequence of the event is indicated. These actual-occurrence event trees do not usually identify all reactor plant functions available to prevent severe core damage stemming from the reported event, but they do specify the major functions associated with the reported event which maintained the plant in a safe condition.

4. Event tree describing the sequence of interest considers the impact of the LER failures on the mitigation sequence for a postulated initiating event, as described previously. Failed and degraded functions related to the LER event are identified. These failed and degraded functions are based on the effect of the LER event on specific safety-related systems of the plant at which the failure occurred.

Standardized event trees were used for the sequence of interest trees when the initiating event was a loss of feedwater, loss of offsite power, small LOCA, or steam line break. To permit this, mitigating systems were functionally represented on these trees. The success criteria for these functions vary from plant to plant, and certain functions do not exist at every plant (for example, runback following a load rejection). The effect of the LER event on the specific safety-related systems of the plant at which the failure occurred was carefully considered when the failed or degraded states of the event tree functions were determined. The standardized event trees used in the study are described in Appendix A.

Following identification of the 1969–1979 precursors, the LER data base was sampled to determine the completeness of the precursor identification process. This sample consisted of 10% of the 1969–1979 data base and was separately reviewed for events that should have been selected as precursors but were missed. Based on this check, it is estimated that 83% of precursors for the years of interest have been identified. No increases were made in any numerical value subsequently calculated in the study because of this error rate.

Reference

1. U.S. Nuclear Regulatory Commission, *Regulatory Guide 1.16, Reporting of Operating Information, Appendix A: Technical Specifications*, Rev. 4 (August 1975).

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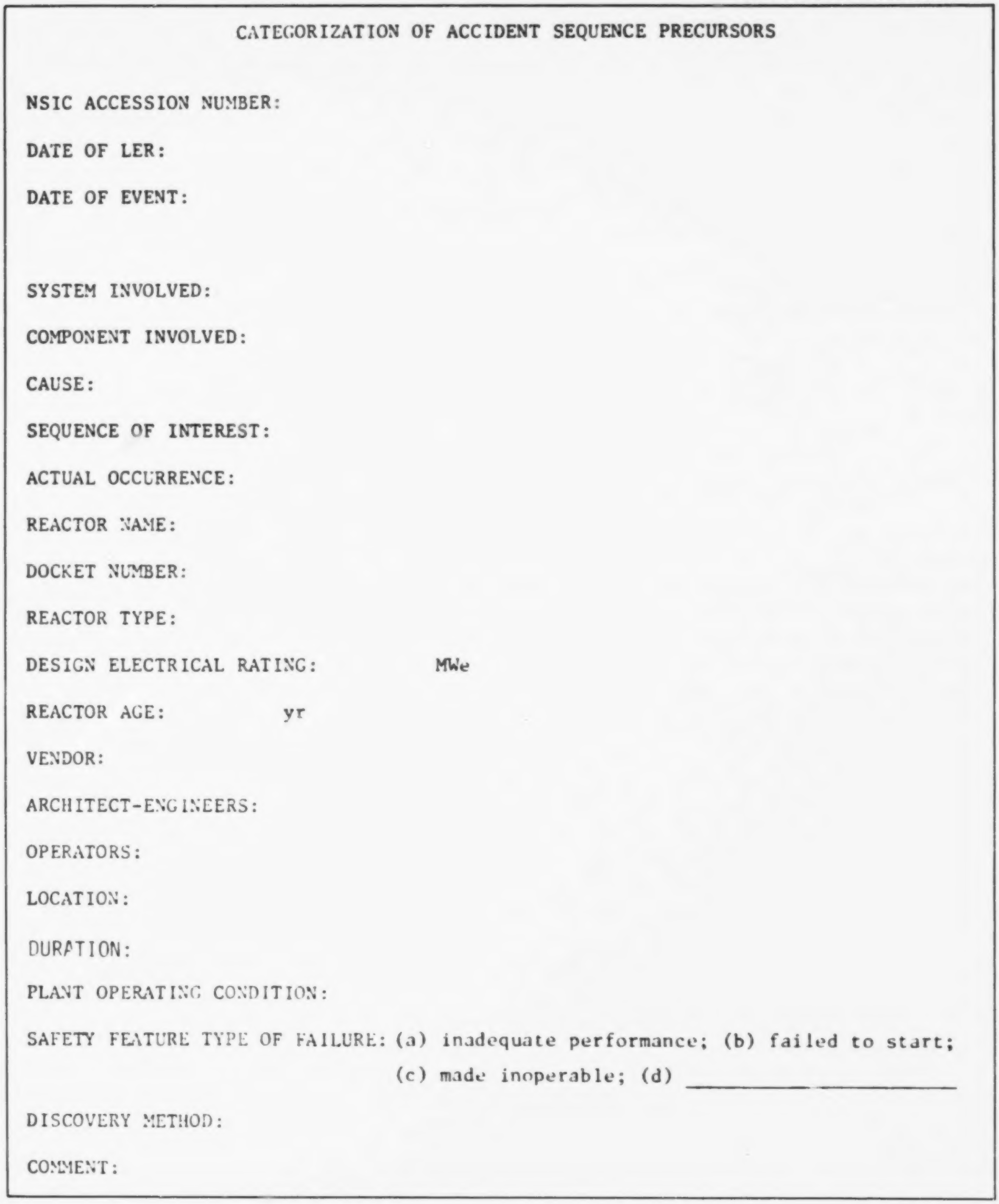

CATEGORIZATION OF ACCIDENT SEQUENCE PRECURSORS

NSIC ACCESSION NUMBER:

DATE OF LER:

DATE OF EVENT:

SYSTEM INVOLVED:

COMPONENT INVOLVED:

CAUSE:

SEQUENCE OF INTEREST:

ACTUAL OCCURRENCE:

REACTOR NAME:

DOCKET NUMBER:

REACTOR TYPE:

DESIGN ELECTRICAL RATING: MWe

REACTOR AGE: yr

VENDOR:

ARCHITECT-ENGINEERS:

OPERATORS:

LOCATION:

DURATION:

PLANT OPERATING CONDITION:

SAFETY FEATURE TYPE OF FAILURE: (a) inadequate performance; (b) failed to start; (c) made inoperable; (d) ______________________

DISCOVERY METHOD:

COMMENT:

Fig. 3.2. Categorization of accident sequence precursors form.

4. QUANTIFICATION OF PRECURSORS AND IDENTIFICATION OF THOSE CONSIDERED SIGNIFICANT

Those events considered significant among the 169 precursors were identified by a ranking method based on a measure of the probability of severe core damage associated with each precursor. This probability is an estimate of the chance of potential severe core damage, given the conditions of the precursor event exist. It was estimated using initiating event frequencies, failure time intervals, and function failure probabilities, which were determined, when possible, from the failure information contained in the precursors themselves. These items were combined, using the sequence-of-interest event tree structures determined for each precursor and included in Appendix B, to obtain the probability of severe core damage measure associated with each event. Precursors with high associated probabilities were selected as significant precursors. These calculations are described in the following sections.

4.1 Determination of Initiating Event Frequencies and Function Failure Probabilities

As a consequence of the study selection criteria, unusual initiating events and complete failures of safety-related functions were selected as precursors. Initiating event frequencies were calculated based on the event occurrence experience during the number of reactor years of operation in the 1969–1979 period. Function failure probabilities were calculated based on an estimate of the total number of test demands (determined from test intervals) and the number of additional, nontest demands to which the function would be expected to respond.

The failure information obtained from the precursors was qualified in several ways to provide reasonable frequency and probability estimates:

1. Only failure and demand data associated with plants that went critical after January 1, 1969,* were considered in the calculations. This was done for two reasons:

- Plant operation prior to January 1, 1969, was not reviewed as a part of this study. Therefore, early-in-life failure information is lacking for plants that went critical before January 1, 1969.
- System designs in plants critical before January 1, 1969, are frequently different from system designs employed in plants that went critical after that time. Failure information associated with such early designs may not be directly associable with failure information related to later system designs.

2. When failures were accounted for, the chance of rectifying a demand failure or an initiating event was included, based on engineering judgment, as follows.

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*The following plants were critical prior to January 1, 1969: Big Rock Point, Dresden 1, Haddam Neck, Humboldt Bay, Indian Point 1, La Crosse, San Onofre, and Yankee Rowe.

- If the failure was incapable of short-term rectification, either from the control room or at the failed piece of equipment, then the failure was considered total and given a rating of 1.
- If the failure appeared capable of short-term rectification at the failure location, and this location was accessible, then the probability of failing to rectify the event was assumed to be 0.5, and the failure was given a rating of 0.5.
- If the failure appeared capable of short-term rectification from the control room, then the probability of failing to rectify the event was assumed to be 0.1, and the failure was given a rating of 0.1.

The above "weighting factors" were applied to each failure, and the resulting failure fractions were then summed to determine the effective number of failures observed.

3. Potential demand failures were separated from actual demand failures. Certain function failures were discovered at other times (e.g., during a plant walk-through). Such failures were considered to be potential failures on demand because if they had not been discovered, the function would likely have failed when next demanded. When such failures existed, two failure probability estimates were calculated: a minimum probability based only on true demand plus testing failures and a maximum probability based on true demands, testing, and potential demand failures. The average of these two numbers was used in subsequent determinations of precursor significance.

Initiating event and failure descriptions, weighting fractions, demand and test interval assumptions, and subsequent initiating event frequencies and demand failure probabilities calculated based on the severe core damage precursor information are included in Appendix C. Certain initiating event frequencies and demand failure probabilities used in the severe core damage probability calculations could not be determined from information in the precursor data. In such cases, previous experience and engineering judgment were used to define these values. This information is also included in Appendix C.

Initiating event frequencies and demand failure probabilities estimated from the precursors identified in this study are listed, for reference, in Table 4.1.

4.2 Calculation of Probability Measures Associated With Each Precursor

The probability measure associated with each precursor was calculated using previously estimated initiating event frequencies, failure time intervals, function demand failure probabilities, and the sequence-of-interest event trees included in Appendix B. These probabilities were calculated in a consistent manner, which accounted for these differing situations associated with different events:

1. If an initiating event occurred as part of a selected event, then the probability measure was calculated based on the sequence-of-interest

Table 4.1. Initiating event frequencies and demand failure probabilities determined using precursor information

Event	Frequency or failure probability
Combined PWR and BWR loss of offsite power (≥30 min), per year	0.041
PWR loss of offsite power (≥30 min), per year	0.048
BWR loss of offsite power (≥30 min), per year	0.030
PWR small LOCA, per year	8.3×10^{-3}
BWR small LOCA, per year	2.1×10^{-2}
PWR AFW failure, per demand	1.1×10^{-3}
PWR HPI failure, per demand	1.3×10^{-3}
PWR long-term core cooling (sump recirculation) failure, per demand	1.2×10^{-3}
PWR emergency power failure, per demand	1.8×10^{-3}
PWR steam generator isolation failure, per demand	1.2×10^{-3}
PWR HPI for steam line break mitigation (concentrated boric acid injection) failure, per demand	2.8×10^{-3}
BWR RCIC and HPCI failure, per demand	3.9×10^{-3}
BWR ADS failure, per demand	2.7×10^{-2}
BWR emergency power failure, per demand	5.0×10^{-3}
BWR HPCI failure, per demand	5.7×10^{-2}
BWR reactor vessel isolation failure, per demand	3.0×10^{-3}

event tree associated with that selected event. The possibility of rectification was considered for initiating events. This was done by assigning a probability to the initiating event equal to the severity rating for that event, as identified in Table C.1, Appendix C.

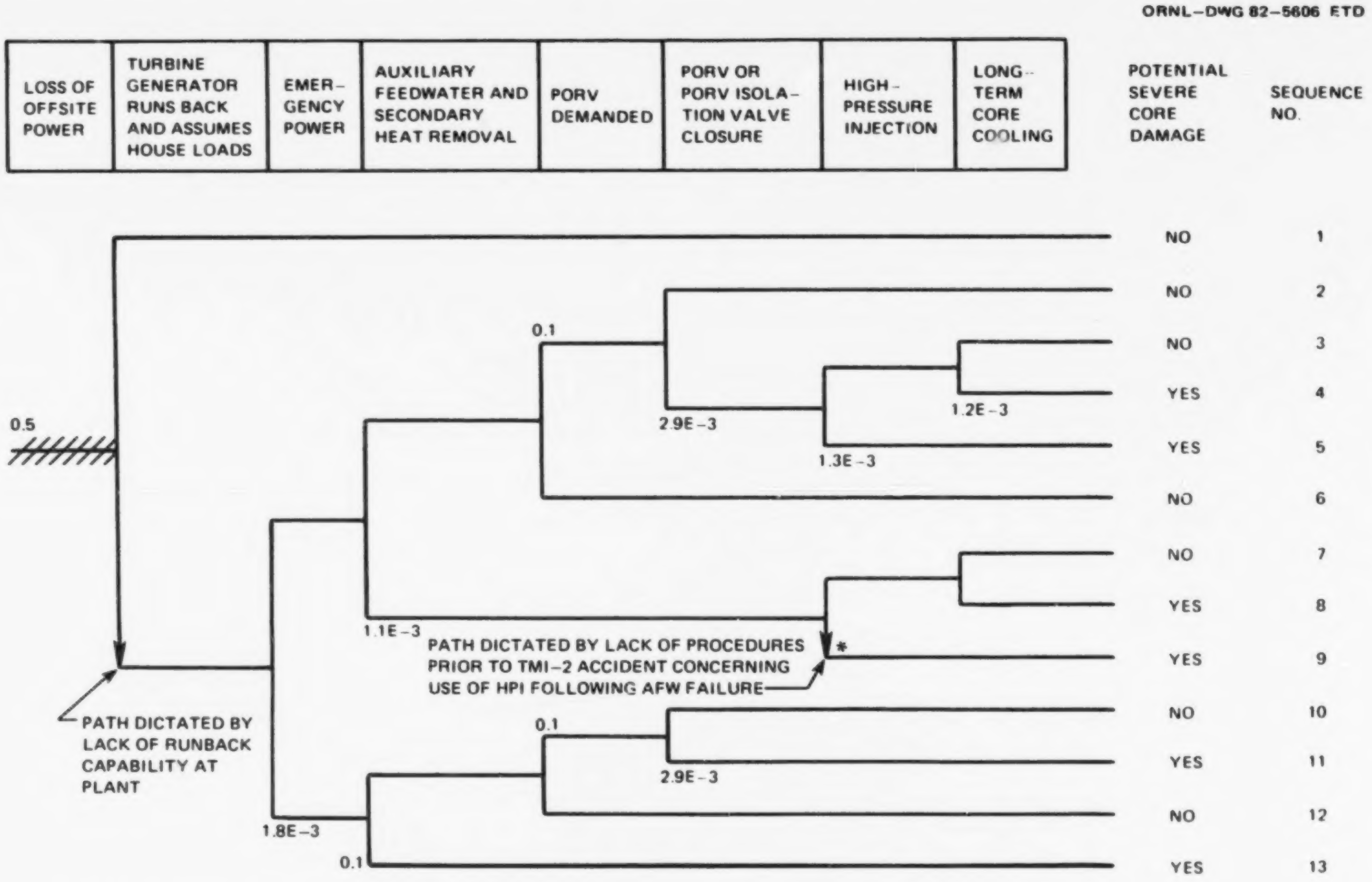
2. If an initiating event did not occur as part of a selected precursor, then the probability of the initiating event for the precursor sequence of interest was based on previously determined initiating event frequencies and the time during which the precursor existed. Event durations were based on information included in each LER, if provided. If the event was discovered during testing, then one-half of the test period (typically 30 d), was assumed. If such a precursor resulted in failures that affected more than one event tree, then the probability measure associated with the precursor was calculated using all applicable event trees. The probability of subsequent severe core damage during the same time period but without the failed or degraded functions associated with the selected precursor was subtracted to yield a contribution for the failure event itself.

3. If a precursor occurred when the plant was not at power, then the probability of the event occurring while at power or shortly after shutdown (while decay heat was still significant) was included in the calculations.

4. For each precursor, the probabilities assigned to each event tree branch were based on the information included in Table C.1 of Appendix C. If a mitigating function was not failed or degraded, then the demand failure probability associated with the function and calculated in Sect. 4.1 was used. These values are listed in the right-hand column of Table C.1. If a mitigating function was degraded but not failed, then a failure probability equal to ten times the generic demand failure probability was used. Use of the factor of 10 was based on engineering judgment. If a mitigating function failed, then a failure probability equal to the severity rating associated with the particular event was used. This allowed some chance of rectification when appropriate. The severity ratings associated with each event are listed under the event descriptions in Table C.1.

5. For precursors occurring in plants that went critical before 1969, the design of mitigating systems was considered before function failure probabilities estimated from post-1968 plant data were used in the probability calculations. Function failure probabilities were revised, based on engineering judgment, when necessary to reflect unusual system designs.

Two precursors illustrate this calculational process. The first event, NSIC 93702, involved the loss of offsite power at Turkey Point 4 caused by a turbine-generator trip and an isolated startup transformer. This event is documented in Appendix B. The sequence-of-interest event tree for this event is shown in Fig. 4.1. The probabilities included on each branch have been obtained, as previously described, from Table C.1. Because the precursor involved an initiating event, the initiating event


ORNL-DWG 82-5606 ETD
LOSS OF OFFSITE POWER
TURBINE GENERATOR RUNS BACK AND ASSUMES HOUSE LOADS
EMER-GENCY POWER
AUXILIARY FEEDWATER AND SECONDARY HEAT REMOVAL
PORV DEMANDED
PORV OR PORV ISOLA-TION VALVE CLOSURE
HIGH-PRESSURE INJECTION
LONG-TERM CORE COOLING
POTENTIAL SEVERE CORE DAMAGE
SEQUENCE NO.
NO 1
NO 2
NO 3
YES 4
YES 5
NO 6
NO 7
YES 8
YES 9
NO 10
YES 11
NO 12
YES 13
0.5
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
PATH DICTATED BY LACK OF PROCEDURES PRIOR TO TMI-2 ACCIDENT CONCERNING USE OF HPI FOLLOWING AFW FAILURE
*
0.1
2.9E-3
PATH DICTATED BY LACK OF RUNBACK CAPABILITY AT PLANT
1.8E-3
0.1

*USE OF HPI FOLLOWING AFW FAILURE NOT INCLUDED IN MITIGATION PROCEDURES.

Fig. 4.1. Example probability calculation [based on NSIC 93702, sequence of interest for two-unit trip at Turkey Point 3 and 4 (loss of offsite power at Turkey Point 4)].

probability was assigned a value of 0.5, the severity rating (chance of failing to rectify in the short term) identified in the event description section of Table C.1. Calculating the combined branch probabilities associated with the branches leading to potential severe core damage results in a probability of severe core damage measure of 6.4×10^{-4} for the event.*

The second event, NSIC 152835, involved an unavailability of the ESFAS undervoltage trip circuitry at Calvert Cliffs 1, which was discovered during trouble shooting. This event is also documented in Appendix B. The sequence-of-interest event tree for this precursor is shown in Fig. 4.2. As before, the probabilities associated with each branch have been obtained from Table C.1. The failure probability associated with the precursor event (the emergency power failure) was assigned based on the severity rating identified in the event description. No initiating event occurred with the precursor; however, a failure duration of 7.5 h was specified. The loss-of-offsite-power frequency identified in Table C.1 of 0.041/year, combined with this failure interval, results in an estimated initiating event probability of 3.5×10^{-5}. The combined branch probability measure for branches leading to severe core damage is 1.3×10^{-6}.† To eliminate event tree branches not involved with the precursor and to calculate only the additional contribution associated with the precursor, the sequence-of-interest event tree was calculated a second time using the same initiating event probability but with all branches assigned demand failure probabilities from Table C.1 (no failed or degraded states). This value was subtracted from the value obtained in the first calculation. For this example, this second value (1.9×10^{-8}) had no effect on the probability calculated for the precursor.

The values taken from Table C.1 and used in each calculation are shown on the associated precursor sequence-of-interest trees in Appendix C. In cases where functional failures had an impact on mitigation of more than one postulated initiating event, and the contribution from the other initiators caused an increase in the precursor probability, then the results of these additional calculations are also included on the event trees.

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*Calculations for the probability of severe core damage (P_{SCD}) were obtained as follows (sequence numbers are in brackets):

$$\begin{aligned} P_{SCD} = {} & P_{SCD}[\text{seq. 4}] + P_{SCD}[\text{seq. 5}] + P_{SCD}[\text{seq. 9}] + P_{SCD}[\text{seq. 11}] \\ & + P_{SCD}[\text{seq. 13}]\ [\text{seq. 8 does not exist because of the dictated HPI failure path}]\ . \end{aligned}$$

$$\begin{aligned} P_{SCD} = {} & [(1.2E-3)(\sim 1)(2.9E-3)(0.1)(\sim 1)(\sim 1)(1)(0.5)]\ [\text{seq. 4}] \\ & + [(1.3E-3)(2.9E-3)(0.1)(\sim 1)(\sim 1)(1)(0.5)]\ [\text{seq. 5}] \\ & + [(1)(1.1E-3)(\sim 1)(1)(0.5)]\ [\text{seq. 9}] \\ & + [(2.9E-3)(0.1)(1 - 0.1)(1.8E-3)(1)(0.5)]\ [\text{seq. 11}] \\ & + [(0.1)(1.8E-3)(1)(0.5)]\ [\text{seq. 13}] \\ P_{SCD} = {} & 6.4E-4\ . \end{aligned}$$

†Calculations were made in the same manner as those for NSIC 93702.

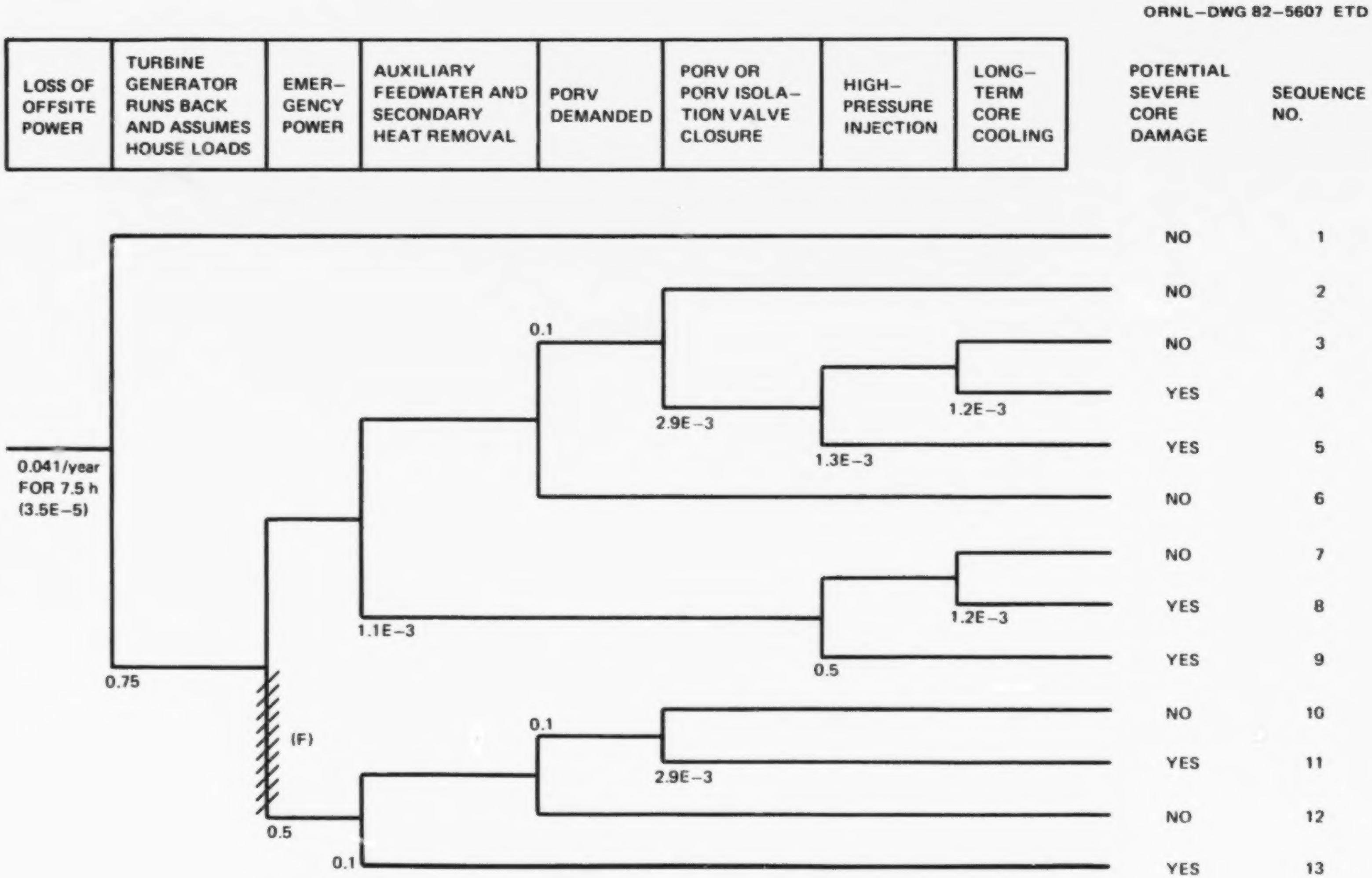
ORNL-DWG 82-5607 ETD
LOSS OF OFFSITE POWER
TURBINE GENERATOR RUNS BACK AND ASSUMES HOUSE LOADS
EMERGENCY POWER
AUXILIARY FEEDWATER AND SECONDARY HEAT REMOVAL
PORV DEMANDED
PORV OR PORV ISOLATION VALVE CLOSURE
HIGH-PRESSURE INJECTION
LONG-TERM CORE COOLING
POTENTIAL SEVERE CORE DAMAGE
SEQUENCE NO.
0.041/year
FOR 7.5 h
(3.5E-5)
0.75
(F)
0.5
0.1
1.1E-3
0.1
2.9E-3
1.3E-3
1.2E-3
0.5
1.2E-3
0.1
2.9E-3
NO 1
NO 2
NO 3
YES 4
YES 5
NO 6
NO 7
YES 8
YES 9
NO 10
YES 11
NO 12
YES 13

Fig. 4.2. Example probability calculation (based on NSIC 152835, sequence of interest for engineered safety features actuation system failed at Calvert Cliffs 1).

The resulting probability measures were translated into a two-digit number that could be conveniently stored in the previous computerized listing of precursor events (Table 3.1). These numbers, listed under the heading of significance category, are equal to $-10 \log_{10}$ (precursor probability measure). The information in Table 3.1, sorted in ascending order by significance category (events of higher significance first), is shown in Table 4.2. The comments provided in Chap. 3 pertaining to the heading and abbreviations associated with Table 3.1 are applicable to Table 4.2 as well.

Because the frequencies and function demand failure probabilities used in these calculations are derived from data from the post-1968 light-water reactor population, the probability measures determined for each precursor cannot be directly associated with the probability of severe core damage resulting from the actual precursor event at the specific reactor plant at which it occurred. However, the probabilities calculated in this study are considered representative of severe core damage probabilities resulting from the occurrence of the selected events at plants representative of the general reactor population.

The distribution of events selected as precursors as a function of significance category and probability measure is shown in Fig. 4.3. As can be seen, the number of events is maximum in the 30 to 40 significance category range (10^{-3} to 10^{-4} probability) and decreases both above and below these probability values. This is to be expected and is a result of two factors: the number of less serious events is known to be greater than the number of more serious events and the criteria used in the study emphasized the selection of more serious events, which resulted in selection of comparatively fewer less significant events. This bias toward higher consequence events does not alter any of the conclusions of the work. Only events of little consequence were not selected.

A rough estimate of the core damage frequency was obtained by using the precursor probability measures, the initiating event frequencies, and the demand failure probabilities developed earlier. This method may overestimate the frequency by a factor of ~3.

The precursors of interest in this estimate are those that included initiating events, because these precursors define the expected number of initiators over the period of observation. The calculation was done by (1) assuming an initiating frequency of 1 divided by the total number of reactor years under observation (432) for each precursor event of interest, multiplying this by the probability measure (probability of subsequent severe core damage) associated with the precursor, and summing over the total number of events of interest and then (2) adding the frequency of severe core damage associated with expected initiators not included in the LER data base (primarily losses of feedwater) and thus not considered in the ASP study.* This process can be represented in equation form as follows.

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*A consistent approach for losses of feedwater would require their identification, along with any degraded and failed mitigating functions that occurred with them, in the same manner used with such events as a loss of offsite power. Because losses of feedwater are not usually reportable via the LER system, this could not be accomplished here. In lieu of this, a standard event tree approach was used to predict the frequency of severe core damage for these events.

Table 4.2. Precursors listed by significance category

TABLE COLUMN HEADING ABBREVIATIONS

ACCESS: 6 DIGIT NSIC ACCESSION NUMBER
E DATE: EVENT DATE
SEQ: SEQUENCE OF INTEREST FOR THE EVENT
ACTUAL OCCURRENCE: DESCRIPTION OF EVENT
PLANT NAME: NAME OF PLANT AND UNIT NUMBER
DOC: PLANT DOCKET NUMBER
SY:SYSTEM ABBREVIATION:
COMPXX: SYSTEM COMPONENT CODE:
O: PLANT OPERATING STATUS:
D: DISCOVERY METHOD (O-OPERATIONAL EVENT, T-TESTING)
E: HUMAN ERROR INVOLVED (N-NO, Y-YES)

I: TRANSIENT/ACCIDENT INDUCED BY ACTUAL OCCURRENCE (N-NO, Y-YES)
AGEX: PLANT AGE AT THE TIME OF THE EVENT IN DAYS
SC: SIGNIFICANCE CATEGORY
RATE: PLANT ELECTRICAL RATING IN MEGAWATTS ELECTRIC
T: PLANT TYPE (B=BWR, P=PWR)
V: PLANT NSSS VENDOR
AE: PLANT ARCHITECT ENGINEER
OPR: PLANT LICENSEE ABBREVIATION:
CRITXX: PLANT CRITICALITY DATE
SD: PLANT INDEFINATELY SHUT DOWN

ACCESS	E DATE	SEQ	ACTUAL OCCURRENCE	PLANT	DOC	SY	COMPXX	O	D	E	I	AGEX	SC	RATE	T	V	AE	OPR	CRITXX	S
153164	790328	LOFW	LOSS OF FEEDWATER & OPEN PORV	TMI 2	320	CJ	VALVEX	E	O	Y	Y	365	00	906	P	B	BR	MEC	780328	*
101444	750322	LOFW	CABLE TRAY FIRE CAUSED EXTENSIVE DAMAGE	BRN.FERRY1	259	SF	ELECON	E	O	Y	Y	582	04	1065	B	G	UX	TVA	730817	
138830	780320	LOFW	FAILURE OF NNI & STEAM GENERATOR DRYOUT	RANCHOSECO	312	IE	INSTRU	E	O	Y	Y	1281	06	918	P	B	BX	SMU	740916	
90421	740407	LOFW	INOPERABLE AFW PUMPS DURING PLANT SHUTDOWN	PT.BEACH 1	266	SF	FILTER	D	O	N	N	1252	16	497	P	W	BX	WMP	701102	
91676	740508	LOFW	FAILURE OF 3 AUX FWDTR PMPS TO START AT TEST	TKY.POINT3	250	SF	PUMPXX	E	T	Y	N	565	16	693	P	W	BX	FPL	721020	
108078	751105	LOFW	INOPERABLE AFW PUMPS DURING PLANT STARTUP	KEWAUNEE	305	SF	FILTER	C	O	N	N	608	16	535	P	W	FP	WPS	740307	
133706	771211	LOFW	AUX. FEEDWATER PUMPS INOPERABLE DURING TEST	DVS-BESSE1	346	SF	PUMPXX	G	T	N	N	121	16	906	P	B	BX	TEC	770812	
149450	790502	LOFW	LOSS OF FEEDWATER FLOW	OYSTER CRK	219	CJ	VALVEX	E	O	Y	Y	3651	16	650	B	G	BR	JCP	690503	
63129	710324	LOOP	LOSS OF OFFSITE POWER	LACROSSE	409	EA	CKTBRK	E	O	N	Y	1352	18	50	B	A	SL	DLP	670711	
88451	740119	LOOP	LOSS OF OFFSITE POWER	HAD.NECK	213	EA	INSTRU	E	O	N	Y	2401	18	575	P	W	SW	CYA	670624	
128906	770831	LOFW	LOSS OF NO-BREAK-POWER AND FEEDWATER CONTROL	COOPER	298	SF	GENERA	E	O	N	Y	1287	19	778	B	G	BR	NPP	740221	
137305	780325	LOFW	LOW-LOW WATER LEVEL IN ONE STEAM GENERATOR	FARLEY 1	348	SH	VALVEX	E	O	Y	N	228	19	829	P	W	BX	APC	770809	
149961	790603	LOFW	HPCI FAILS TO START GIVEN LOFW	HATCH 1	366	SF	PUMPXX	E	O	Y	Y	334	19	784	B	G	SS	GPC	780704	
116212	760720	LOOP	APPARENT LOOP & FAILURE OF SAFETY RELATED COMP	MILLSTONE2	336	EB	RELAYX	E	O	Y	Y	277	20	870	P	C	BX	NNE	751017	
61434	700717	LOOP	LOSS OF OFFSITE POWER	HUMBDLTBAY	133	EA	INSTRU	E	O	Y	Y	2708	21	65	B	G	BX	PGE	630216	*
61565	710902	LOOP	LOOP AND FAILURE OF A DIESEL GENERATOR TO LOAD	PALISADES	255	EA	RELAYX	U	O	N	Y	101	22	805	P	C	BX	CPC	710524	
137918	780423	MSLB	MULTIPLE STUCK-OPEN RELIEF VALVES	TMI 2	320	HB	VALVEX	E	O	N	Y	26	22	906	P	B	BR	MEC	780328	*
137543	780413	LOOP	LOSS OF OFFSITE POWER WHILE SHUTDOWN	CALCLIFFS1	317	EA	CKTBRK	G	O	N	Y	1284	23	845	P	C	BX	BGE	741007	
139565	780514	LOOP	LOSS OF OFFSITE POWER DURING REFUELING	ST.LUCIE 1	335	EA	CKTBRK	H	O	Y	Y	752	23	802	P	C	EX	FPL	760422	
140335	780728	LOOP	LOOP AND DIESEL GENERATOR FAILURE	BVRVALLEY1	334	EB	TRANSF	E	O	N	Y	809	23	852	P	W	SW	DLC	760510	
142462	781127	LOCA	LOSS OF VITAL INST. BUS-REACTOR TRIP	SALEM 1	272	EB	GENERA	E	O	Y	Y	716	23	1090	P	W	UX	PEG	761211	
85566	731119	LOOP	LOSS OF A.C. POWER CAUSE HPCI/RCIC TO FAIL	BRN.FERRY1	259	SF	RELAYX	B	T	N	Y	65	25	1065	B	G	UX	TVA	730817	
85738	731119	LOFW	RCIC/HPCI FAILS DURING TESTING	BRN.FERRY1	259	SF	VALVEX	B	T	N	Y	65	25	1065	B	G	UX	TVA	730817	
152187	790903	LOOP	SWITCHYARD LOCKOUT DUE TO CABLE DROP AT STORM	ST.LUCIE 1	335	EE	ENGINE	G	O	N	Y	1229	25	802	P	C	EX	FPL	760422	
153810	791120	LOFW	RCIC TURBINE TRIP WITH HPCI UNAVAILABLE	BRUNSWICK1	325	CE	MECFUN	E	O	N	Y	1139	25	821	B	G	UE	CPL	761008	
103002	750429	LOFW	MULTIPLE VALVE FAILURES & RCIC INOPERABLE	BRUNSWICK2	324	CC	VALVEX	E	O	Y	N	40	26	821	B	G	UE	CPL	750320	
103077	750501	LOCA	RCP SEAL FAILURE	ROBINSON 2	261	CB	PUMPXX	E	O	N	Y	1684	26	700	P	W	EX	CPL	700920	

Table 4.2 (continued)

66996	711010	LOCA	TRANSIENT AND BLOWDOWN	MILLSTONE1	245	CC	VALVEX	E	O	N	Y	349	27	660	B	G	EX	NNE	701026	
128569	770715	LOCA	SAFETY RELIEF VALVE FAILS TO RESET	BRUNSWICK2	324	CA	VALVEX	E	O	N	Y	281	27	821	B	G	UE	CPL	750320	
152563	791002	SGTR	STEAM GENERATOR TUBE BREAK	PRAIRIEIS1	282	HB	HTEXCH	E	O	N	Y	2131	27	530	P	W	PX	NSP	731201	
36147	690715	LOOP	REACTOR TRIP WITH LOSS OF OFFSITE POWER	HAD.NECK	213	EB	CKTBRK	E	O	Y	Y	752	28	575	P	W	SW	CYA	670724	
59484	710112	LOCA	SUMP ISO. VALVES CLOSED	PT.BEACH 1	266	SF	VALVEX	E	T	N	N	71	28	497	P	W	BX	WMP	701102	
65757	710205	LOOP	LOSS OF OFFSITE POWER	PT.BEACH 1	266	EA	CKTBRK	G	O	N	Y	95	28	497	P	W	BX	WMP	701102	
85370	731021	LOOP	LOOP,EXCESSIVE RCS COOLDOWN,SFTY INJ.&INS BUS	GINNA	244	EA	ELECON	E	O	N	Y	1443	28	470	P	W	GX	RGE	691108	
115870	760706	LOCA	IMPROPER INSULATION	VT.YANKEE	271	SF	VALVEX	G	T	N	N	1565	28	514	B	G	EX	VYC	720324	
116780	760810	LOOP	GAS TURBINE FAILS DURING PLANT TRIP	MILLSTONE1	245	SF	ENGINE	E	O	N	Y	2153	28	660	B	G	EX	NNE	701026	
120443	761101	LOFW	TWO ELECTROMATIC RV FAILURES	QUAD-CTES2	265	SF	VALVEX	C	T	N	N	1650	28	789	B	G	SL	CWE	720426	
124222	770408	LOFW	SIX MAIN STEAM RELIEF VALVES FAIL TO LIFT	D.ARNOLD	331	SF	VALVEX	G	T	N	N	1110	28	538	B	G	BX	IEL	740323	
63144	710308	LOOP	FAILURE OF BOTH DIESEL GENER. DURING TESTING	ROBINSON 2	261	EE	ENGINE	E	T	N	N	169	29	700	P	W	EX	CPL	700920	
81523	730618	LOFW	FAILURE OF AFW PUMPS TO AUTO-START	TKY.POINT4	251	SF	INSTRU	B	O	Y	N	7	29	693	P	W	BX	FPL	730611	
115875	760626	LOOP	LOSS OF OFFSITE POWER DURING REFUELING	HAD.NECK	213	EB	RELAYX	H	O	Y	Y	3169	29	575	P	W	SW	CYA	670724	
123150	770303	MSLB	50% OPEN ATMOSPHERIC DUMP VALVES	CRYSTALRV3	302	IF	GENERA	E	O	N	Y	48	29	825	P	B	GX	FPC	770114	
127384	770712	LOCA	DUMMY SIGNALS INSTALLED ON INSTRUMENTENTATION	ZION 2	304	IA	INSTRU	G	T	Y	Y	1296	29	1040	P	W	SL	CWE	731224	
130788	770924	LOCA	STUCK OPEN PORV	DVS-BESSE1	346	CB	VALVEX	E	O	N	Y	43	29	906	P	B	BX	TEC	770812	
132927	771129	LOOP	LOSS OF OFFSITE POWER	DVS-BESSE1	346	EB	XXXXXX	E	O	Y	Y	109	29	906	P	B	BX	TEC	770812	
148764	790118	MSLB	STUCK OPEN STEAM DUMP VALVES	BVRVALLEY1	334	HB	VALVEX	E	O	Y	Y	983	29	852	P	W	SW	DLC	760510	
89205	731130	LRTR	FAILED RCP SHAFT AT 92% POWER	SURRY 1	280	CB	PUMPXX	E	O	N	Y	517	30	822	P	W	SW	VEP	720701	
106616	750913	LOOP	LOSS OF OFFSITE PWR & RELF.VALV STKS OPN	PILGRIM 1	293	EB	CKTBRK	D	O	N	Y	1184	30	655	B	G	BX	BEC	720616	
120293	761111	LOOP	PLANT SERVICE WATER STRAINERS PLUGGED	HATCH 1	321	WA	FILTER	E	O	N	N	791	30	786	B	G	SS	GPC	740912	
141097	780329	LOCA	STUCK OPEN PORV	TMI 2	320	EB	GENERA	B	O	N	Y	1	30	906	P	B	BR	MEC	780328	*
146744	790112	LOFW	LOSS OF VITAL BUS WHILE AT POWER	DVS-BESSE1	346	EB	GENERA	E	O	Y	N	518	30	906	P	B	BX	TEC	770812	
150882	790606	LOOP	BOTH DG'S TRIPPED DURING TEST	CRYSTALRV3	302	EE	ENGINE	G	T	Y	N	873	30	825	P	B	GX	FPC	770114	
95040	740823	LOFW	HPCI INJECTION VALVE AND RCIC FAIL	BRN.FERRY2	260	SF	VALVEX	B	T	N	N	33	31	1065	B	G	UX	TVA	740720	
106333	750909	LOFW	HPCI FOUND INOPERABLE	QUAD-CTES2	265	SF	PUMPXX	E	T	N	N	904	31	789	B	G	SL	CWE	730310	
64600	701226	LOOP	SHUTDOWN OF BUCHANAN STATION	IND.POINT1	3	EA	RELAYX	U	O	N	Y	3068	32	265	P	B	UE	CEC	620802	*
71694	720517	LOOP	LOSS OF OFFSITE POWER	PALISADES	255	EB	RELAYX	G	T	N	Y	359	32	805	P	C	BX	CPC	710524	
73655	720720	LOOP	LOSS OF OFFSITE POWER	IND.POINT1	3	EA	ELECON	E	O	N	Y	3640	32	265	P	B	UE	CEC	620802	*
79565	721201	LOOP	LOSS OF NORMAL STATION POWER	VT.YANKEE	271	EB	TRANSF	E	O	N	Y	252	32	514	B	G	EX	VYC	720324	
93702	740425	LOOP	REACTOR TRIP WITH LOSS OF OFFSITE POWER	TKY.POINT4	251	EB	RELAYX	E	O	N	Y	318	32	693	P	W	BX	FPL	730611	
117944	760810	LOOP	REACTOR TRIP WITH LOOP & DIESEL GENS.RUNNING	MILLSTONE2	336	EA	ELECON	E	O	N	Y	298	32	870	P	C	BX	NNE	751017	
128935	770822	LOOP	MOMENTARY LOSS OF OFFSITE POWER	FTCALHOUN1	285	EA	CKTBRK	E	O	N	Y	1477	32	457	P	C	GH	DPP	730806	
130119	770924	LOOP	REACTOR TRIP DUE TO LOSS OF OFFSITE POWER	PALISADES	255	EB	CKTBRK	E	O	N	Y	2315	32	805	P	C	BX	CPC	710524	
132943	771125	LOOP	REACTOR TRIP WITH LOSS OF OFFSITE POWER	PALISADES	255	EB	CKTBRK	E	O	N	Y	2377	32	805	P	C	BX	CPC	710524	
132958	771211	LOOP	REACTOR TRIP WITH LOSS OF OFFSITE POWER	PALISADES	255	EB	CKTBRK	E	O	N	Y	2393	32	805	P	C	BX	CPC	710524	
135006	770916	LOOP	LOSS OF OFFSITE POWER	FARLEY 1	348	EB	RELAYX	C	O	Y	Y	38	32	829	P	W	BX	APC	770809	
97578	741017	LOOP	LOSS OF OFFSITE POWER DURING TESTING	PALISADES	255	EB	RELAYX	G	T	Y	Y	1242	33	805	P	C	BX	CPC	710524	
104817	750729	INAA	ALL ADS VALVES OPEN INADVERTENTLY	HATCH 1	321	SF	VALVEX	E	T	Y	Y	321	33	786	B	G	SS	GPC	740912	
120439	761101	LOFW	TWO ELECTROMATIC RV FAILURES	QUAD-CTES1	254	SF	VALVEX	E	T	N	N	1841	33	789	B	G	SL	CWE	711018	
143219	770713	LOOP	LOSS OF OFFSITE POWER	IND.POINT3	286	EA	ELECON	G	O	N	Y	463	33	965	P	W	UE	PNY	760406	
78418	730202	LOCA	VALVE FAILURE TO OPEN DURING TESTING	MA.YANKEE	309	SF	VALVEX	E	T	N	N	102	34	825	P	C	SW	MAY	721023	
80138	720610	LOOP	FLOODING OF TURBINE BUILDING	QUAD-CTES1	254	CF	PUMPXX	G	O	Y	N	236	34	789	B	G	SL	CWE	711018	

Table 4.2 (continued)

100415	750225	LOFW	ALL DRYWELL HIGH PRESSURE SWITCHES ISOLATED	FITZPATRIK	333	IA	INSTRU	E	T	Y	N	100	34	821	B	G	SW	PNY	741117	
125563	770516	LOOP	REACTOR TRIP WITH LOSS OF OFFSITE POWER	ST.LUCIE 1	335	EA	XXXXXX	G	O	N	Y	389	34	802	P	C	EX	FPL	760422	
65757	710416	LOCA	FAILURE OF CONTAINMENT SUMP ISO VALVES	PT.BEACH 1	266	SF	VALVEX	C	T	N	N	165	35	497	P	W	BX	WMP	701102	
120995	761111	LOCA	VALVES FAIL TO OPEN FOR DECAY HEAT SYSTEM	RANCHOSECO	312	SF	VALVEX	G	T	N	N	787	35	918	P	B	BX	SMU	740916	
154286	791128	LOCA	ONE PMP FAILED + 1 DEGRADED IN CLD SHTDN	SALEM 1	272	SF	PUMPXX	G	O	N	N	1082	35	1090	P	W	UX	PEG	761211	
39380	711208	ECIT	SAFETY VALVE OPERATION AFTER LOFW	DRESDEN 3	249	CC	INSTRU	E	O	N	Y	312	36	794	B	G	SL	CWE	710131	
44751	700427	LOFW	3 OF 4 STEAM DRUM SCRAM SENSORS FAIL	DRESDEN 1	010	IC	INSTRU	U	T	N	N	3844	36	200	B	G	BX	CWE	591015	
47814	700505	ECIT	DEPRESSURIZATION INCIDENT	DRESDEN 2	237	CC	INSTRU	E	O	N	Y	150	36	794	B	G	SL	CWE	700107	
74242	711231	ECIT	HIGH COOLANT LEVEL	NINEMIPT1	220	CC	VESSEL	E	O	Y	Y	847	36	620	B	G	UX	NMP	690905	
97107	741022	MSLB	BIT AUTO INJECTION FAILURE	ZION 2	304	SF	INSTRU	E	O	Y	N	302	36	1040	P	W	SL	CWE	731224	
103892	750613	LOCA	STUCK OPEN PORV	OCONEE 3	287	CB	VALVEX	E	O	Y	Y	281	36	887	P	B	UX	DPC	740905	
123118	770218	LOFW	BOTH AFW PUMPS UNAVAILABLE	RANCHOSECO	312	SF	PUMPXX	E	T	Y	N	886	36	918	P	B	BX	SMU	740916	
150499	790628	LOFW	RCIC AND HPCI ISOLATE FOLLOWING REACTOR SCRAM	HATCH 2	366	SF	INSTRU	G	T	N	N	359	36	784	B	G	SS	GPC	780704	
152183	790813	LOCA	OPEN PWR OPERATED RELIEF VALVE + ISO.VALVE	HAD.NECK	213	HB	VALVEX	E	O	N	Y	4433	36	575	P	W	SW	CYA	670724	
152951	791015	LOOP	REACTOR TRIP WITH LOSS OF OFFSITE POWER	DVS-BESSE1	346	IC	CKTBRK	E	O	N	Y	794	36	906	P	B	BX	TEC	770812	
77916	721229	LOCA	MALFUNCTION OF SEVERAL VALVES	OYSTER CRK	219	CH	VALVEX	E	O	Y	Y	1334	37	650	B	G	RB	JCP	690503	
83833	730908	LOOP	LOSS OF OFFSITE POWER	OYSTER CRK	219	EB	RELAYX	D	O	Y	Y	1589	37	650	B	G	BR	JCP	690503	
145209	781220	LOCA	TWO STUCK OPEN PROV'S DURING COLD SHUTDOWN	FTCALHOUN1	285	CJ	VALVEX	G	O	Y	Y	1962	37	457	P	C	GH	DPP	730806	
105540	750817	LOCA	LOW FLOW FEEDWATER LINE SEVERED AT 6X4 REDUCER	QUAD-CTES2	265	CH	PIPEXX	C	O	N	Y	1208	38	789	B	G	SL	CWE	720426	
39024	720125	LOOP	LOSS OF OFFSITE POWER	BG ROCK PT	155	EA	CKTBRK	E	O	N	Y	3406	39	72	B	G	BX	CPC	620927	
61043	710120	LOOP	LOSS OF OFFSITE POWER	LACROSSE	409	EA	RELAYX	G	O	Y	Y	1289	39	50	B	A	SL	DLP	670711	
75074	720817	LOOP	LOSS OF LOAD	LACROSSE	407	EA	RELAYX	C	O	Y	Y	1863	39	50	B	A	SL	DPL	670711	
82198	730704	LOOP	REACTOR/TURBINE TRIP DURING TEST	TKY.POINT3	250	EB	INSTRU	E	O	N	Y	257	39	693	P	W	BX	FPL	721020	
86990	731121	LOOP	WORKER BUMPS RELAY CAUSING LOOP	NINEMIPT1	220	EA	RELAYX	B	O	Y	Y	7072	39	620	B	G	BX	CPC	620927	
102146	750320	LOOP	LOSS OF OFFSITE POWER	BRUNSWICK2	324	EB	ELECON	G	O	Y	Y	6	39	821	B	G	UE	CPL	750320	
103207	750525	LOOP	BREAKER & RELAY FAILURE DURING TEST	TKY.POINT4	251	EB	RELAYX	G	T	N	N	713	39	693	P	W	BX	FPL	730611	
130111	770901	LOOP	REACTOR TRIP & LOSS OF OFFSITE POWER	COOK 1	315	EA	RELAYX	E	O	N	Y	957	39	1054	P	W	AE	IME	750118	
103111	750419	LOOP	CONDENSER EMERG. DISCHARGE VLVS FAIL TO OPEN	OCONEE 3	287	WA	CKTBRK	G	T	Y	N	226	40	887	P	B	UX	DPC	740905	
153333	791115	LOFW	AFW UNAVAIL DUE TO MAINTENANCE AND INSPECTION	COOK 1	315	SF	PUMPXX	G	T	Y	N	1762	40	1054	P	W	AE	IME	750118	
135932	780206	LOOP	LOSS OF OFFSITE POWER	PILGRIM 1	293	EA	ELECON	E	O	N	Y	2061	42	655	B	G	BX	BEC	720616	
140140	780806	LOOP	LOSS OF OFFSITE POWER	PILGRIM 1	293	EA	ELECON	E	O	N	Y	2242	42	655	B	G	BX	BEC	720616	
150943	790727	LOOP	LOSS OF OFFSITE POWER	PILGRIM 1	293	EA	ELECON	E	O	N	Y	2597	42	655	B	G	BX	BEC	720616	
151635	790828	LOOP	LOSS OF OFFSITE POWER	PILGRIM 1	293	EA	CKTBRK	E	O	N	Y	2629	42	655	B	G	BX	BEC	720616	
153003	791024	LOCA	FAILURE TO PROPERLY POSITION VALVES AFTER TEST	OCONEE 2	270	SH	VALVEX	E	O	Y	N	2173	43	887	P	B	UX	DPC	731111	
89252	740217	LOOP	FAILURE OF DIESEL TO START/LOAD;2 AFW PMPS OUT	ZION 2	304	EB	GENERA	E	T	N	N	55	44	1040	P	W	SL	CWE	731224	
108869	751220	LOOP	TWO DIESELS FAIL TO START	HATCH 1	321	EE	ENGINE	G	T	N	N	464	44	786	B	G	SS	GPC	740912	
149230	790321	LOOP	BOTH EMERGENCY SERVICE WATER SYSTEM OUT	D.ARNOLD	311	WG	FILTER	E	T	N	N	1824	45	538	B	G	BX	IEL	740323	
104379	750627	EQUK	EARTHQUAKE OCCURS	HUMBDLTBAY	133	XX	XXXXXX	G	O	N	N	4513	46	65	B	G	BX	PGE	630216	*
150271	790603	LOFW	BOTH RHR SERVICE WATER PMPS NOT OPERABLE	BRUNSWICK2	324	SF	PUMPXX	E	T	Y	N	1536	46	821	B	G	UE	CPL	750320	
109295	751219	LOCA	FROZEN BWST LEVEL INPULSE LINES WHILE OPRTING	OCONEE 1	269	SF	INSTRU	E	O	N	N	974	48	887	P	B	UX	DPC	730419	
65969	710908	LOCA	OPEN ELECTROMATIC RELIEF VALVE	PALISADES	255	CB	VALVEX	G	O	Y	Y	107	49	805	P	C	BX	CPC	710524	
132979	770515	LOOP	FUEL SUPPLY VALVES FOUND SHUT DURING INSPECT.	MILLSTONE2	336	EE	ENGINE	G	O	Y	N	576	49	870	P	C	BX	NNE	751017	
144187	771210	LOOP	DIESEL GENERATOR FOUND INOPERABLE	MILLSTONE1	245	EE	ENGINE	E	T	N	N	2616	50	660	B	G	EX	NNE	701026	
148892	790222	LOOP	UNAVAILABILITY OF TWO DIESEL GENERATORS	FARLEY 1	348	EB	INSTRU	E	O	N	N	562	50	829	P	W	BX	APC	770809	

Table 4.2 (continued)

150742	790622	LOFW	MAIN STACK SAMPLING SYSTEM LOST	PEACHBTOM3	278	SF	CKTBRK	E	O	N	N	2175	50	1065	B	G	BX	PEC	740807
93553	741208	LOOP	TWO DIESEL GENERATORS MALFUNCTION	HATCH 1	321	EE	ENGINE	Z	T	N	N	87	51	786	B	G	SS	GPC	740912
121533	770104	LOOP	TWO DIESEL GENERATORS TRIP	BRUNSWICK1	325	EE	ENGINE	E	T	N	N	87	51	821	B	G	UE	CPL	761008
131225	770828	LOOP	TWO DIESEL GENERATORS FAIL TO START	PEACHBTOM2	227	EE	ENGINE	G	T	Y	N	1443	51	1065	B	G	GX	PEC	730916
132155	771129	LOOP	DIESEL GENERATOR TRIPS DURING TESTING	DRESDEN 3	249	EE	ENGINE	E	T	N	N	2493	51	794	B	G	SL	CWE	710131
150051	790612	LOOP	FAILURE OF TWO DIESEL GENERATORS	DRESDEN 2	237	EE	ENGINE	E	T	N	N	3473	51	794	B	G	SL	CWE	700107
153167	790926	LOOP	LOSS OF STANDBY POWER SOURCE DURING PWR OPRT	OCONEE 1	269	EE	ENGINE	E	O	N	N	2351	52	887	P	B	UX	DPC	730419
153167	790926	LOOP	LOSS OF STANDBY POWER SOURCE DURING PWR OPRT	OCONEE 2	270	EE	ENGINE	E	O	N	N	2145	52	887	P	B	UX	DPC	731111
112309	760308	LOOP	GAS TURBINE BECOMES INOPERABLE	MILLSTONE1	245	SF	ENGINE	E	T	N	N	1957	54	660	B	G	EX	NNE	701026
112310	760315	LOOP	GAS TURBINE FAILS TO ACHIEVE RATED SPEED	MILLSTONE1	245	SF	ENGINE	E	T	N	N	1966	54	660	B	G	EX	NNE	701026
133004	770613	LOOP	3/4 DIESELS INOPERABLE	PEACHBTOM3	278	EE	ENGINE	E	T	Y	N	1041	54	1065	B	G	BX	PEC	740807
135079	771123	LOCA	SI PUMP BREAKERS INCORRECTLY RACKED OUT	ROBINSON 2	261	SF	CKTBRK	G	0	Y	N	2621	54	700	P	W	EX	CPL	700920
147400	790219	MSLB	MAIN STEAM STOP VALVES FAILED TO CLOSE AT TEST	PT.BEACH 2	301	HB	VALVEX	E	T	N	N	3031	54	497	P	W	BX	WMP	720530
125106	770506	LOCA	FAILURE TO CLEAR OVERPRESSURE DURING HEATUP	SALEM 1	272	SF	PUMPXX	C	O	Y	N	146	55	1090	P	W	UX	PEG	761211
130889	771011	LOCA	FLOODING OF VALVE PIT DURING 0 PWR PHYSIC TST	SURRY 2	281	WB	VALVEX	B	T	Y	N	1928	55	822	P	W	SW	VEP	730307
149250	790414	MSLB	MSIVS FAILED TO CLOSE DURING TEST	TROJAN	344	HB	VALVEX	G	T	N	N	1216	55	1130	P	W	BX	PGE	751215
137384	780318	LOCA	RELAY FAILURE	TMI 1	289	SF	PUMPXX	B	T	N	N	1382	56	819	P	B	GX	MEC	740605
141706	781024	LOOP	LOSS OF 1 DG WHILE 2ND OUT OF SERVICE	RANCHOSECO	312	EE	ENGINE	E	O	N	N	1499	56	918	P	B	BX	SMU	740916
124920	770416	MSLB	STEAM GENERATOR OVERFILL	CRYSTALRV3	302	HH	INSTRU	G	T	N	Y	92	58	825	P	B	GX	FPC	770114
137335	780404	LOFW	IC INADVERNTLY RENDERED INOPERABLE	DRESDEN 2	237	SF	XXXXXX	E	O	Y	N	3034	58	784	B	G	SL	CWE	710131
60227	701204	MSLB	FAILURE OF SEVERAL MSIV'S TO CLOSE	DRESDEN 2	237	CC	VALVEX	E	T	N	N	331	59	794	B	G	SL	CWE	700107
97779	741124	RCPT	FAILURE OF RPS TO SEE RCP TRIPS	ARKANSAS 1	313	IA	RELAYX	E	T	Y	Y	110	59	850	P	B	BX	APL	740806
147399	790221	LOOP	BOTH DIESEL GENERATORS UNAVAILABLE	KEWAUNEE	305	EE	ENGINE	E	T	N	N	1812	59	535	P	W	FP	WPS	740307
152835	790731	LOOP	OVR VOLTG PROT TRIP FOUND WHILE TRBLE SHTG	CALCLIFFS1	317	IB	INSTRU	E	O	N	N	1758	59	845	P	C	BX	BGE	741007
139573	780615	LOOP	UNAVAILABILITY OF BOTH DIESEL GENERATORS	COOK 2	316	EE	ENGINE	E	O	Y	N	97	63	1100	P	W	AE	IME	780310
147223	790106	MSLB	TURBINE TRIP AND STUCK FW VALVE	CRYSTALRV3	302	HH	VALVEX	E	O	N	N	722	64	825	P	B	GX	FPC	770114
147383	790223	LOOP	TWO DIESEL GENERATORS NOT AVAILABLE (TWICE)	COOK 1	315	EE	ENGINE	E	O	Y	N	1497	64	1054	P	W	AE	IME	750118
141455	781004	LOOP	BOTH DIESEL GENERATORS OUT OF SERVICE	RANCHOSECO	312	EE	ENGINE	E	O	N	N	1479	65	918	P	B	BX	SMU	740916
101078	750318	LOOP	DIESEL GENERATOR FIRE	FITZPATRIK	333	EE	ENGINE	E	O	N	N	110	66	821	B	G	SW	PNY	741117
124201	770322	LOOP	DIESEL GENERATOR FIELD FAILS TO FLASH	DRESDEN 3	249	EE	GENERA	E	T	N	N	2273	66	794	B	G	SL	CWE	710131
127010	770714	LOOP	FAILURE OF TWO DIESEL GENERATORS	DRESDEN 3	249	EE	ENGINE	E	T	N	N	2160	66	794	B	G	SL	CWE	710131
132947	771202	LOOP	DIESEL GENERATOR FAILS TO START	DRESDEN 2	237	EE	ENGINE	H	T	N	N	2890	66	794	B	G	SL	CWE	700107
140162	780824	LOOP	DIESEL GENERATOR FAILS TO START	DRESDEN 2	237	EE	ENGINE	E	T	N	N	2761	66	794	B	G	SL	CWE	710131
143533	771010	LOOP	DIESEL GENERATOR LOAD CYCLES	BRUNSWICK1	325	EE	ENGINE	E	T	N	N	367	66	821	B	G	UE	CPL	761008
152638	791017	LOOP	UNAVAIL OF 1 AFW PUMP AND 1 DIESEL GENERATOR	COOK 2	316	SF	PUMPXX	E	O	Y	N	586	66	1100	P	W	AE	IME	780310
141523	781017	LOCA	INOPERABLE LPSI PUMPS	CALCLIFFS2	318	SF	PUMPXX	G	O	N	N	686	67	845	P	C	BX	BGE	761130
143255	770730	LOOP	DIESEL GENERATORS FAILED TO START AT TEST	SALEM 1	272	EE	ENGINE	G	T	N	N	231	67	1090	P	W	UX	PEG	761211
153338	791101	LOOP	INCORRECT DIESEL GENERATOR MAINT. WHILE REFUEL	COOK 2	316	EE	ENGINE	H	O	Y	N	601	67	1100	P	W	AE	IME	780310
143296	771020	LOCA	INADVERTENT VALVE CLOSING DURING TEST	MA.YANKEE	309	SF	VALVEX	E	T	Y	N	1823	68	825	P	C	SW	MAY	721023
146540	790110	LOOP	ONE DG FAILED WHILE 2ND OUT DUE TO MAINTENANCE	KEWAUNEE	305	EE	ENGINE	E	O	N	N	1770	68	535	P	W	FP	WPS	740307
151433	790911	LOCA	INCORRECT RHR SERVICE PUMP BREAKER RACKED OUT	BRUNSWICK2	324	CF	PUMPXX	E	T	Y	N	1636	70	821	B	G	UE	CPL	750320
153686	791127	LOOP	DG AND CHARGING PMP SUCT VALVE UNAVAILABLE	BVRVALLEY1	334	EE	ENGINE	E	O	Y	N	1296	71	852	P	W	SW	DLC	760510
120207	761028	MSLB	FAILURE OF RWST-CHARGING PUMP SUCTION VALVES	TROJAN	344	SF	VALVEX	G	O	Y	N	318	72	1130	P	W	BX	PGE	751215
135077	771026	MSLB	THERMO WELL COUPLING FAILED AFTER SAFETY INJ.	ROBINSON 2	261	SF	ACCUMU	G	O	N	N	2593	72	700	P	W	EX	CPL	700920

Table 4.2 (continued)

142329	781126	MSLB	HEAT TRACING CIRCUIT FAILURE	IND.POINT2	247	SF	PIPEXX	G	O	N	N	2014	72	873	P	W	UE	CEC	730522	
122366	770110	MSLB	SENSING LINES FROZEN	ARKANSAS 1	313	IB	INSTRU	E	O	N	N	888	73	850	P	B	BX	APL	740806	
154639	791209	LOOP	BOTH DIESEL GENERATORS INOPERABLE	DVS-BESSE1	346	EE	ENGINE	G	T	N	N	849	73	906	P	B	BX	TEC	770812	
104087	750619	LOCA	CLOSED SI TANK ISOLATION VALVES	MA.YANKEE	309	SF	VALVEX	C	T	Y	N	969	74	825	P	C	SW	MAY	721023	
32429	690313	MSLB	LOOP ISOLAT. VALVES FAILED TO SHUT	IND.POINT1	3	CB	VALVEX	G	T	Y	N	2415	75	265	P	B	UE	CEC	620802	*
132942	771209	LOOP	BOTH DIESEL GENERATORS INOPERABLE	PRAIRIEIS1	282	EE	INSTRU	H	T	Y	N	1469	75	530	P	W	PX	NSP	731201	
140693	780912	LOOP	BOTH DIESEL GENERATORS OUT OF SERVICE	BVRVALLEY1	334	EE	CKTBRK	G	T	N	N	855	75	852	P	W	SW	DLC	760510	
140691	780905	LOOP	BOTH DIESEL GENERATORS OUT OF SERVICE	BVRVALLEY1	334	EE	CKTBRK	G	T	N	N	848	76	852	P	W	SW	DLC	760510	
149962	790505	LOOP	DIESEL GENERATOR UNABLE TO CARRY LOAD	HATCH 1	321	EE	GENERA	G	T	N	N	1535	77	786	B	G	SS	GPC	740912	
89153	740221	MSLB	OPEN RWST ISOLATION VALVES	PRAIRIEIS1	282	SF	VALVEX	E	T	Y	N	82	82	530	P	W	PX	NSP	731201	

ABBREVIATIONS:

ACCESS: 6 DIGIT NSIC ACCESSION NUMBER
E DATE: EVENT DATE
SEQ: SEQUENCE OF INTEREST FOR THE EVENT
- ECIT - EXCESSIVE COOLANT INVENTORY
- EQUK - EARTHQUAKE
- INAA - INADVERTANT ADS ACTUATION
- LOFW - LOSS OF FEEDWATER
- LOOP - LOSS OF OFFSITE POWER
- LOCA - LOSS OF COOLANT ACCIDENT
- LRTR - LOCKED ROTOR ACCIDENT
- MSLB - MAIN STEAM LINE BREAK
- RCPT - REACTOR COOLANT PUMP TRIP
- SGTR - STEAM GENERATOR TUBE RUPTURE

ACTUAL OCCURRENCE: DESCRIPTION OF EVENT
PLANT NAME: NAME OF PLANT AND UNIT NUMBER
DOC: PLANT DOCKET NUMBER
SY:SYSTEM ABBREVIATION:

STANDARD GENERIC CODE	SYSTEM DESCRIPTION
	REACTOR
RA	REACTOR VESSEL INTERNALS
RB	REACTIVITY CONTROL SYSTEMS
RC	REACTOR CORE

Table 4.2 (continued)

REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

CA	REACTOR VESSELS AND APPURTENANCES
CB	COOLANT RECIRCULATION SYSTEMS AND CONTROLS
CC	MAIN STEAM SYSTEMS AND CONTROLS
CD	MAIN STEAM ISOLATION SYSTEMS AND CONTROLS
CE	REACTOR CORE ISOLATION COOLING SYSTEMS AND CONTROLS
CF	RESIDUAL HEAT REMOVAL SYSTEMS AND CONTROLS
CG	REACTOR COOLANT CLEANUP SYSTEMS AND CONTROLS
CH	FEEDWATER SYSTEMS AND CONTROLS
CI	REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS
CJ	OTHER COOLANT SUBSYSTEMS AND THEIR CONTROLS

ENGINEERED SAFETY FEATURES

SA	REACTOR CONTAINMENT SYSTEMS
SB	CONTAINMENT HEAT REMOVAL SYSTEMS AND CONTROLS
SC	CONTAINMENT AIR PURIFICATION AND CLEANUP SYSTEMS AND CONTROLS
SD	CONTAINMENT ISOLATION SYSTEMS AND CONTROLS
SE	CONTAINMENT COMBUSTIBLE GAS CONTROL SYSTEMS AND CONTROLS
SF	EMERGENCY CORE COOLING SYSTEMS AND CONTROLS
SG	CONTROL ROOM HABITABILITY SYSTEMS AND CONTROLS
SH	OTHER ENGINEERED SAFETY FEATURE SYSTEMS AND THEIR CONTROLS

INSTRUMENTATION AND CONTROLS

IA	REACTOR TRIP SYSTEMS
IB	ENGINEERED SAFETY FEATURE INSTRUMENT SYSTEMS
IC	SYSTEMS REQUIRED FOR SAFE SHUTDOWN
ID	SAFETY RELATED DISPLAY INSTRUMENTATION
IE	OTHER INSTRUMENT SYSTEMS REQUIRED FOR SAFETY
IF	OTHER INSTRUMENT SYSTEMS NOT REQUIRED FOR SAFETY

ELECTRIC POWER SYSTEMS

EA	OFFSITE POWER SYSTEMS AND CONTROLS
EB	AC ONSITE POWER SYSTEMS AND CONTROLS
EC	DC ONSITE POWER SYSTEMS AND CONTROLS
ED	ONSITE POWER SYSTEMS AND CONTROLS (COMPOSITE AC AND DC)
EE	EMERGENCY GENERATOR SYSTEMS AND CONTROLS
EF	EMERGENCY LIGHTING SYSTEMS AND CONTROLS
EG	OTHER ELECTRIC POWER SYSTEMS AND CONTROLS

Table 4.2 (continued)

FUEL STORAGE AND HANDLING SYSTEMS

FA	NEW FUEL STORAGE FACILITIES
FB	SPENT FUEL STORAGE FACILITIES
FC	SPENT FUEL POOL COOLING AND CLEANUP SYSTEMS AND CONTROLS
FD	FUEL HANDLING SYSTEMS

AUXILIARY WATER SYSTEMS

WA	STATION SERVICE WATER SYSTEMS AND CONTROLS
WB	COOLING SYSTEMS FOR REACTOR AUXILIARIES AND CONTROLS
WC	DEMINERALIZED WATER MAKE-UP SYSTEMS AND CONTROLS
WD	POTABLE AND SANITARY WATER SYSTEMS AND CONTROLS
WE	ULTIMATE HEAT SINK FACILITIES
WF	CONDENSATE STORAGE FACILITIES
WG	OTHER AUXILIARY WATER SYSTEMS AND THEIR CONTROLS

AUXILIARY PROCESS SYSTEMS

PA	COMPRESSED AIR SYSTEMS AND CONTROLS
PB	PROCESS SAMPLING SYSTEMS
PC	CHEMICAL, VOLUME CONTROL AND LIQUID POISON SYSTEMS AND CONTROLS
PD	FAILED FUEL DETECTION SYSTEMS
PE	OTHER AUXILIARY PROCESS SYSTEMS AND THEIR CONTROLS

OTHER AUXILIARY SYSTEMS

AA	AIR CONDITIONING, HEATING, COOLING AND VENTILATION SYSTEMS AND CONTROLS
AB	FIRE PROTECTION SYSTEMS AND CONTROLS
AC	COMMUNICATION SYSTEMS
AD	OTHER AUXILIARY SYSTEMS AND THEIR CONTROLS

STEAM AND POWER CONVERSION SYSTEMS

HA	TURBINE-GENERATORS AND CONTROLS
HB	MAIN STEAM SUPPLY SYSTEM AND CONTROLS (OTHER THAN CC)
HC	MAIN CONDENSER SYSTEMS AND CONTROLS
HD	TURBINE GLAND SEALING SYSTEMS AND CONTROLS
HE	TURBINE BYPASS SYSTEMS AND CONTROLS
HF	CIRCULATING WATER SYSTEMS AND CONTROLS
HG	CONDENSATE CLEAN-UP SYSTEMS AND CONTROLS
HH	CONDENSATE AND FEEDWATER SYSTEMS AND CONTROLS (OTHER THAN CH)
HI	STEAM GENERATOR BLOWDOWN SYSTEMS AND CONTROLS
HJ	OTHER REATURES OF STEAM AND POWER CONVERSION SYSTEMS (NOT INCLUDED ELSEWHERE)

Table 4.2 (continued)

	RADIOACTIVE WASTE MANAGEMENT SYSTEMS
MA	LIQUID RADIOACTIVE WASTE MANAGEMENT SYSTEMS
MB	GASEOUS RADIOACTIVE WASTE MANAGEMENT SYSTEMS
MC	PROCESS AND EFFLUENT RADIOLOGICAL MONITORING SYSTEMS
MD	SOLID RADIOACTIVE WASTE MANAGEMENT SYSTEMS
	RADIATION PROTECTION SYSTEMS
BA	AREA MONITORING SYSTEMS
BB	AIRBORNE RADIOACTIVITY MONITORING SYSTEMS
XX	OTHER SYSTEMS
ZZ	SYSTEM CODE NOT APPLICABLE

COMPXX: SYSTEM COMPONENT CODE:

COMPONENT TYPE (COMPONENT CODE)	COMPONENT TYPE INCLUDES
ACCUMULATORS (ACCUMU)	SCRAM ACCUMULATORS SAFETY INJECTION TANKS SURGE TANKS HOLDUP/STORAGE TANKS
AIR DRYERS (AIRDRY)	
ANNUNCIATOR MODULES (ANNUNC)	ALARMS BELLS BUZZERS CLAXONS HORNS GONGS SIRENS
BATTERIES AND CHARGERS (BATTRY)	CHARGERS DRY CELLS WET CELLS STORAGE CELLS
BLOWERS (BLOWER)	COMPRESSORS GAS CIRCULATORS FANS VENTILATORS
CIRCUIT CLOSERS/INTERRUPTERS (CKTBRK)	CIRCUIT BREAKERS CONTACTORS CONTROLLERS STARTERS SWITCHES (OTHER THAN SENSORS) SWITCHGEAR
CONTROL RODS (CONROD)	POISON CURTAINS
CONTROL ROD DRIVE MECHANISMS (CRDRVE)	
DEMINERALIZERS (DEMINX)	ION EXCHANGERS

Table 4.2 (continued)

ELECTRICAL CONDUCTORS (ELECON)	BUS CABLE WIRE
ENGINES, INTERNAL COMBUSTION (ENGINE)	BUTANE ENGINES DIESEL ENGINES GASOLINE ENGINES NATURAL GAS ENGINES PROPANE ENGINES
FILTERS (FILTER)	STRAINERS SCREENS
FUEL ELEMENTS (FUELXX)	
GENERATORS (GENERA)	INVERTERS
HEATERS, ELECTRIC (HEATER)	HEAT TRACERS
HEAT EXCHANGERS (HTEXCH)	CONDENSERS COOLERS EVAPORATORS REGENERATIVE HEAT EXCHANGERS STEAM GENERATORS FAN COIL UNITS
INSTRUMENTATION AND CONTROLS (INSTRU)	CONTROLLERS SENSORS/DETECTORS/ELEMENTS INDICATORS DIFFERENTIALS INTEGRATORS (TOTALIZERS) POWER SUPPLIES RECORDERS SWITCHES TRANSMITTERS COMPUTATION MODULES
MECHANICAL FUNCTION UNITS (MECFUN)	MECHANICAL CONTROLLERS GOVERNORS GEAR BOXES VARIDRIVES COUPLINGS
MOTORS (MOTORX)	ELECTRIC MOTORS HYDRAULIC MOTORS PNEUMATIC (AIR) MOTORS SERVO MOTORS
PENETRATIONS, PRIMARY CONTAIN. (PENETR)	AIR LOCKS PERSONNEL ACCESS FUEL HANDLING EQUIPMENT ACCESS ELECTRICAL INSTRUMENT LINE PROCESS PIPING
PIPES, FITTINGS (PIPEXX)	
PUMPS (PUMPXX)	
RECOMBINERS (RECOMB)	
RELAYS (RELAYX)	SWITCHGEAR
SHOCK SUPPRESSORS AND SUPPORT (SUPORT)	HANGERS SUPPORTS SWAY BRACES/STABILIZERS SNUBBERS ANTI-VIBRATION DEVICES
TRANSFORMERS (TRANSF)	

Table 4.2 (continued)

TURBINES (TURBIN)	STEAM TURBINES GAS TURBINES HYDRO TURBINES
VALVES (VALVEX)	VALVES DAMPERS
VALVE OPERATORS (VALVOP)	EXPLOSIVE, SQUIB
VESSELS, PRESSURE (VESSEL)	CONTAINMENT VESSELS DRYWELLS PRESSURE SUPPRESSION PRESSURIZERS REACTOR VESSELS
OTHER COMPONENTS (XXXXXX)	
CODES NOT APPLICABLE (ZZZZZZ)	

O: PLANT OPERATING STATUS:

CODE	STATUS
A	(UNDER) CONSTRUCTION
B	PREOPERATIONAL, STARTUP OR POWER ASCENSION TESTS (IN PROGRESS)
C	ROUTINE STARTUP OPERATIONS
D	ROUTINE SHUTDOWN OPERATIONS
E	STEADY STATE OPERATION
F	LOAD CHANGES DURING ROUTINE POWER OPERATION
G	SHUTDOWN (HOT OR COLD) EXCEPT REFUELING
H	REFUELING
U	UNKNOWN
X	OTHER (INCLUDING SPECIAL TESTS, EMERGENCY SHUTDOWN OPERATIONS, ETC.)
Z	ITEM NOT APPLICABLE

D: DISCOVERY METHOD (O-OPERATIONAL EVENT, T-TESTING)
E: HUMAN ERROR INVOLVED (N-NO, Y-YES)
I: TRANSIENT/ACCIDENT INDUCED BY ACTUAL OCCURRENCE (N-NO, Y-YES)
AGEX: PLANT AGE AT THE TIME OF THE EVENT IN DAYS
SC: SIGNIFICANCE CATEGORY
RATE: PLANT ELECTRICAL RATING IN MEGAWATTS ELECTRIC
T: PLANT TYPE (B=BWR, P=PWR)
V: PLANT NSSS VENDOR
  A-ALLIS CHALMERS
  B-BABCOCK AND WILCOX
  C-COMBUSTION ENGINEERING
  G-GENERAL ELECTRIC
  W-WESTINGHOUSE

Table 4.2 (continued)

AE: PLANT ARCHITECT ENGINEER

AE-AMERICAN ELECTRIC POWER
BR-BURNS AND ROE
BX-BECHTEL
EX-EBASCO
FP-FLOUR POWER
GH-GIBBS AND HILL
GX-GILBERT
PX-PIONEER
RT-BROWN AND ROOT
SL-SARGENT AND LUNDY
SS-SOUTHERN SERVICES
SW-STONE AND WEBSTER
UE-UNITED ENGINEERS
UX-UTILITY
XX-OTHER

OPR: PLANT LICENSEE ABBREVIATION:

ABBR.	LICENSEE
APC	ALABAMA POWER COMPANY
APL	ARKANSAS POWER AND LIGHT COMPANY
APS	ARIZONA PUBLIC SERVICE COMPANY
BEC	BOSTON ELECTRIC COMPANY
BGE	BALTIMORE GAS AND ELECTRIC COMPANY
CEC	CONSOLIDATED EDISON COMPANY
CEI	CLEVELAND ELECTRIC ILLUMINATING COMPANY
CGE	CINCINNATI GAS AND ELECTRIC COMPANY
CPC	CONSUMERS POWER COMPANY
CPL	CAROLINA POWER AND LIGHT COMPANY
CWE	COMMONWEALTH EDISON COMPANY
CYA	CONNECTICUT YANKEE ATOMIC POWER COMPANY
DLP	DAIRYLAND POWER COOPERATIVE
DLC	DUQUESNE LIGHT COMPANY
DPC	DUKE POWER COMPANY
DPP	OMAHA PUBLIC POWER DISTRICT
FPC	FLORIDA POWER CORPORATION
FPL	FLORIDA POWER AND LIGHT COMPANY
GPC	GEORGIA POWER COMPANY
GSU	GULF STATES UTILITIES
HLP	HOUSTON LIGHTING AND POWER COMPANY
IEL	IOWA ELECTRIC LIGHT AND POWER COMPANY
IME	INDIANA AND MICHIGAN ELECTRIC COMPANY
IPC	ILLINOIS POWER COMPANY
JCP	JERSEY CENTRAL POWER AND LIGHT COMPANY
KGE	KANSAS GAS AND ELECTRIC COMPANY
LIL	LONG ISLAND LIGHTING COMPANY
LPL	LOUISIANA POWER AND LIGHT COMPANY
MEC	METROPOLITAN EDISON COMPANY
MPL	MISSISSIPPI POWER AND LIGHT COMPANY
MYA	MAINE YANKEE ATOMIC POWER COMPANY
NIC	NORTHERN INDIANA PUBLIC SERVICE COMPANY
NMP	NIAGARA MOHAWK POWER CORPORATION
NNE	NORTHEAST NUCLEAR ENERGY COMPANY
NPP	NEBRASKA PUBLIC POWER DISTRICT
NSP	NORTHERN STATES POWER COMPANY
PEC	PHILADELPHIA ELECTRIC COMPANY
PEG	PUBLIC SERVICE ELECTRIC AND GAS COMPANY
PEP	POTOMAC ELECTRIC POWER COMPANY
PGC	PORTLAND GENERAL ELECTRIC COMPANY
PGE	PACIFIC GAS AND ELECTRIC COMPANY
PNY	POWER AUTHORITY OF THE STATE OF NEW YORK
PPL	PENNSYLVANIA POWER AND LIGHT COMPANY
PSC	PUBLIC SERVICE COMPANY OF COLORADO
PSI	PUBLIC SERVICE OF INDIANA
PSN	PUBLIC SERVICE OF NEW HAMPSHIRE
PSO	PUBLIC SERVICE COMPANY OF OKLAHOMA
PSP	PUGET SOUND POWER AND LIGHT COMPANY
RGE	ROCHESTER GAS AND ELECTRIC CORPORATION
SCC	SOUTH CAROLINA ELECTRIC AND GAS COMPANY
SCE	SOUTHERN CALIFORNIA EDISON COMPANY
SMU	SACRAMENTO MUNICIPAL UTILITIES DISTRICT
TEC	TOLEDO EDISON COMPANY
TUG	TEXAS UTILITIES GENERATING COMPANY
TVA	TENNESSEE VALLEY AUTHORITY
UEC	UNION ELECTRIC COMPANY
VEP	VIRGINIA ELECTRIC AND POWER COMPANY
VYC	VERMONT YANKEE NUCLEAR POWER CORPORATION
WEP	WISCONSIN ELECTRIC POWER COMPANY
WMP	WISCONSIN-MICHIGAN POWER COMPANY
WPP	WASHINGTON PUBLIC POWER SUPPLY SYSTEM
WPS	WISCONSIN PUBLIC SERVICE CORPORATION
YAC	YANKEE ATOMIC ELECTRIC COMPANY

CRITXX: PLANT CRITICALITY DATE
SD: PLANT INDEFINATELY SHUT DOWN

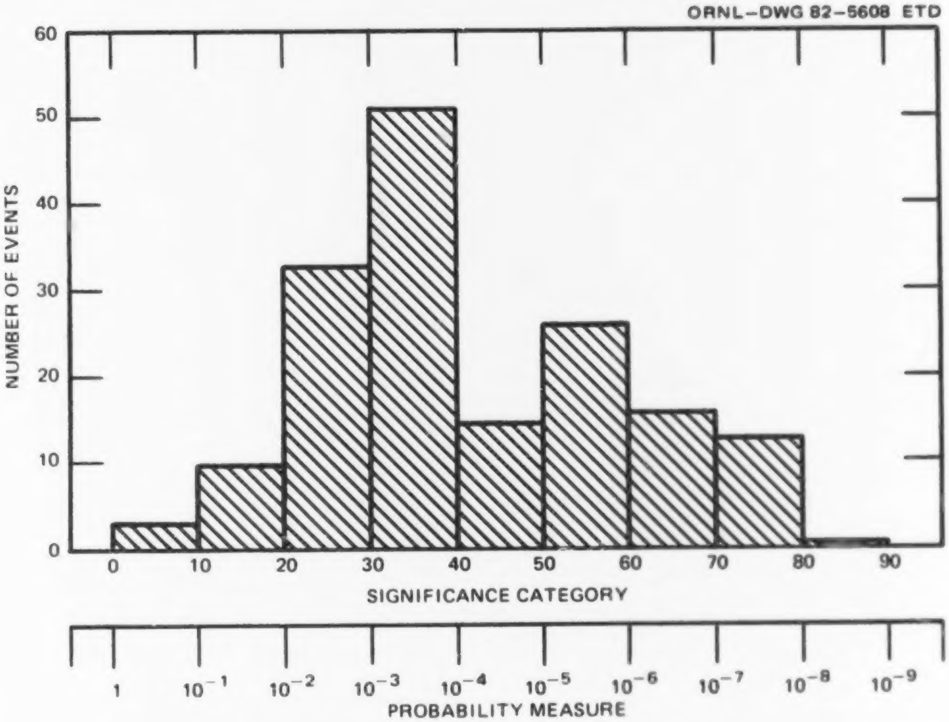

Fig. 4.3. Distribution of precursors as a function of probability measure.

$$\begin{array}{c}\text{Frequency of}\\ \text{severe core}\\ \text{damage}\end{array} = \sum_{\substack{\text{precursors}\\ \text{associated}\\ \text{w/initiat-}\\ \text{ing events}}} \left(\begin{array}{c}\text{frequency}\\ \text{of precursor}\\ \text{event}\end{array}\right) \times \left(\begin{array}{c}\text{probability}\\ \text{of subsequent}\\ \text{severe core}\\ \text{damage associ-}\\ \text{ated w/event}\end{array}\right)$$

$$+ \sum_{\substack{\text{expected init-}\\ \text{iating events}\\ \text{not included in}\\ \text{LER data base}}} \left(\begin{array}{c}\text{frequency}\\ \text{of event}\end{array}\right) \times \left(\begin{array}{c}\text{probability}\\ \text{of subsequent}\\ \text{severe core}\\ \text{damage associ-}\\ \text{ated w/event}\end{array}\right)$$

$$\begin{array}{c}\text{Frequency of}\\ \text{severe core}\\ \text{damage}\end{array} \cong \sum_{\substack{\text{precursors}\\ \text{associated}\\ \text{w/initiat-}\\ \text{ing events}}} (1/432) \times \left(\begin{array}{c}\text{probability of}\\ \text{subsequent severe}\\ \text{core damage asso-}\\ \text{ciated w/precursor}^{*}\end{array}\right)$$

$$+ \begin{array}{c}\text{frequency}\\ \text{of LOFW}\end{array} \times \left(\begin{array}{c}\text{probability of}\\ \text{severe core damage}\\ \text{given LOFW occurs}\end{array}\right)$$

The sum of the products of the probability measures and frequencies from the precursors that involved initiating events and that occurred at power or during startup or shutdown results in a frequency of severe core damage estimate, based on the assumptions and methods used in this study, of 4.2×10^{-3} per plant year for the period 1969–1979. The additional contribution from initiators not in the LER data base, assuming these are associated with losses of main feedwater (all losses of offsite power and less frequent initiating events were reviewed as precursors) and using the event trees developed in Appendix A and the initiating event frequencies and demand failure probabilities estimated in Appendix C, is $\sim 3.4 \times 10^{-4}$. This results in a total estimate of 4.5×10^{-3} for the years of interest in this study. No attempt has been made to bound this number at this time, although this may be the subject of future work.

The above approach includes considerable uncertainty and does not result in an unbiased estimate of the frequency of severe core damage. Specific areas that introduce uncertainties follow.

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[*] From Table 4.2, the probability measure for precursors that involved initiating events (Y under column O, initiating event induced by actual occurrence) can be calculated from the significance category (column SC) and is equal to $10^{-SC/10}$.

1. Because failures are included on specific event trees when applicable and are also used to calculate a probability of function failure (used on event trees when no failed or degraded function exists), the number of expected function failures accounted for on the event trees in the long term will approach twice the number of observed failures.* The impact of individual function overestimations is dependent on the structure of the event trees used, but preliminary analysis (which included the manner in which degraded functions were accounted for in the probability measure calculations and assumed all failures were independent) indicates that the method may overestimate, with respect to a classic probabilistic risk analysis approach, by a factor of 3. While this may be the case, the method does allow one to account for, and place in perspective, specific failures and combinations of failures (which may not be independent) identified in operational data. Using a factor of 3 as the expected overestimation if all failures were independent would result in a revised severe core damage frequency estimate of 1.4×10^{-3}/year from identified precursors plus 3.4×10^{-4}/year from loss of feedwater events for a total estimate of 1.7×10^{-3}/year.

2. The probability measures associated with each precursor were calculated using average numbers from the population of light-water reactors and applying these numbers to sequences that were, in many cases, generic in nature. As such, the numbers do not represent actual probabilities at specific plants and may not, when summed, be representative of the sum of actual probabilities at specific plants.

3. Fifty percent of the cumulative severe core damage contribution resulted from the TMI-2 event. Two other events contributed an additional 32%: the cable tray fire at Browns Ferry 1 (NSIC 101444) and the non-nuclear instrumentation failure and subsequent steam generator dryout at Rancho Seco (NSIC 138830). Changes in these two event probability estimates could have a large impact on cumulative probability contribution.

Although the calculated frequency of severe core damage is higher than the results of previously published probabilistic risk assessments (typically in the range of 5×10^{-5} to 1×10^{-4} per reactor year), both numbers fall within a Poisson distribution 95% confidence interval for a single observed core damage event (the TMI-2 accident) over 432 plant years.

If the TMI-2 accident, the Browns Ferry fire, and the Rancho Seco event are excluded from consideration, the remaining precursors plus the frequency associated with the loss-of-feedwater sequence contribute ~18% of the total number (~7.7×10^{-4}). These remaining precursors include expected transient events and accidents in which the mitigating systems performed as expected (although there were several cases of degraded systems) as well as unusual initiating events not commonly treated in probabilistic risk assessments, including several transients induced by electric bus failures. None of these events contributes more than 5% of this residual. As a comparison, the frequency value calculated by applying the initiating event and demand failure estimates obtained in Appendix C to the four standardized event trees described in Appendix A, in a classic PRA approach, is on the order of 4.3×10^{-4}.

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*If i failures are observed in N events, then i event trees will include an identified function failure. The N − i event trees will include a failure probability for the function of i/N. The total number of failures accounted for in the N events is the number of failures seen (i) plus the number of failures expected based on the probability of failure in the N − i events in which failures were not seen: $i + (N - i)(i/N) \cong 2i$ for $i/N \ll 1$.

4.3 Selection of Significant Precursors

Precursors with probability measures of 10^{-3} or greater were considered significant for the purposes of this study. This cutoff point was chosen for the following reasons:

1. Although the number of low-probability-measure precursors identified in the study is large, the impact of these events is small compared with a considerably smaller number of high-probability-measure events. In fact, all events with probability measures smaller than $\sim 10^{-3}$ contribute <1% to the total.

2. While many low-probability-measure events were selected as precursors based on the selection criteria, many other such events were excluded from selection. An example of such an exclusion would be a degraded PWR auxiliary feedwater function discovered during testing. (The selection criteria required a minimum of two degraded functions for selection.) In addition, certain events were excluded because of their lack of reportability in the LER system. An example of this is a PWR loss of main feedwater with subsequent mitigating function success. The probabilities associated with these two examples (in the 1×10^{-4} to 5×10^{-4} range) are expected to be at the high end of those associated with events that were not selected. Because of this, precursors with probability measures below 10^{-3} were not considered representative of the totality of events with probabilities below 10^{-3}.

The identification of events with probability measures of 10^{-3} or greater as significant resulted in the selection for subsequent analysis of 52 precursors from 1969 to 1979 with significance categories between 0 and 30. These 52 events contribute 99% of the cumulative probability measure of all the precursors.

5. ANALYSIS OF TRENDS IN SELECTED EVENTS

Certain analyses have been performed on the events selected as precursors to determine if significant trends or relationships are discernible. These analyses include:

1. comparison of calculated initiating event frequencies and function failure probabilities based on the precursor information with previous estimates of these numbers,
2. determination of trends in instantaneous failure rates for initiating events and function demand failures based on the precursor information as a function of plant age,
3. development of time lines for initiating events and function failures to visually indicate where and when in plant life these events occurred,
4. consideration of the variation in the number of significant precursor events as a function of plant age,
5. consideration of potential differences between plant types, vendors, architect-engineers, and plant power ratings based on the number of significant precursor events,
6. identification of degraded-function events that occurred within 1 month of each significant precursor to understand what other failures could have been associated with each significant precursor event and to determine if a larger than average number of other failures occurred around the time of significant precursors,
7. determination of percentage of precursors involving human error, and
8. estimation of the probability of a diesel generator failing to start given a nontesting loss-of-offsite-power demand.

Each of these analyses is discussed in the following sections.

5.1 Initiating Event Frequency and Function Failure Probability Comparisons

As discussed in Sect. 4.1, initiating event frequencies and function demand failure probabilities were estimated using data from the 169 selected precursors for the following items:

- loss of offsite power,
- small loss-of-coolant accident,
- failure of emergency power,
- failure of PWR auxiliary feedwater and secondary heat removal,
- failure of PWR high-pressure injection,
- failure of PWR long-term (sump recirculation) cooling,
- failure of PWR steam generator isolation,
- failure of PWR high-pressure injection following a steam line break,

- failure of BWR high-pressure coolant injection and reactor core isolation cooling,
- failure of BWR automatic depressurization,
- failure of BWR high-pressure coolant injection,
- failure of BWR reactor vessel isolation, and
- failure of BWR high-pressure coolant injection (based on separate LER information).

The definitions of failures for these functions are included in Appendix A. The observed failure rates are summarized and compared with calculated *Reactor Safety Study*[1] results in Table 5.1. Several comments are applicable to this comparison.

1. Because the *Reactor Safety Study* failure probabilities were developed for two specific plants, close correspondence with the observed failure rates cannot be expected.

2. The failure probabilities calculated using data from precursor events have been based, for the most part, on demand failures observed during testing, and they do not include contributions from unavailabilities caused by maintenance (unless an actual demand occurred during the maintenance period) and failures to run for extended periods of time.

Even with these factors, the observed and calculated values agree reasonably well in most cases. With three exceptions [BWR small LOCA, PWR auxiliary feedwater system failure, and PWR long-term (sump recirculation) cooling], the values obtained in the ASP study are within a factor of 10 of the *Reactor Safety Study* median estimates.

5.2 Instantaneous Failure Rate Trends

Trends in the instantaneous failure rates for the following initiating events and function failures were investigated using the total time on test plot concept:

- loss of offsite power,
- small loss-of-coolant accident,
- failure of emergency power,
- failure of PWR auxiliary feedwater and secondary heat removal,
- failure of PWR high-pressure injection,
- failure of PWR long-term (sump recirculation) cooling,
- failure of PWR steam generator isolation,
- failure of PWR high-pressure injection following a steam line break,
- failure of BWR high-pressure coolant injection and reactor core isolation cooling,
- failure of BWR automatic depressurization, and
- failure of BWR reactor vessel isolation.

Table 5.1. Initiating event frequencies and demand failure probabilities determined using precursor information compared with values determined in the *Reactor Safety Study*

Event	Frequency or failure probability	
	ASP value	*Reactor Safety Study* value
Loss of offsite power (combined PWR and BWR) (≥30 min), per year	0.041	0.04[a]
PWR loss of offsite power (≥30 min), per year	0.048	
BWR loss of offsite power (≥30 min), per year	0.030	
PWR small LOCA, per year	8.3×10^{-3}	10^{-3}[b]
BWR small LOCA, per year	2.1×10^{-2}	10^{-3}[c]
PWR AFW failure, per demand	1.1×10^{-3}	3.7×10^{-5} (7×10^{-6} to 3×10^{-4})[d]
PWR HPI failure, per demand	1.3×10^{-3}	8.6×10^{-3} (4.4×10^{-3} to 2.7×10^{-2})[e]
PWR long-term core cooling (sump recirculation) failure, per demand	1.2×10^{-3}	1.3×10^{-2} (4.4×10^{-3} to 3.1×10^{-2})[f]
PWR emergency power failure, per demand	1.8×10^{-3}	1×10^{-2}[g]
PWR steam generator isolation failure, per demand	1.2×10^{-3}	
PWR HPI for steam line break mitigation (concentrated boric acid injection) failure, per demand	2.8×10^{-3}	
BWR RCIC and HPCI failure, per demand	3.9×10^{-3}	7.8×10^{-3}[h]
BWR ADS failure, per demand	2.7×10^{-2}	5×10^{-3} (3.3×10^{-3} to 7.5×10^{-3})[i]
BWR emergency power failure, per demand	5.0×10^{-3}	1×10^{-3}[j]
BWR HPCI failure, per demand	5.7×10^{-2}	9.8×10^{-2} (6.8×10^{-2} to 1.4×10^{-1})[k]
BWR reactor vessel isolation failure, per demand	3.0×10^{-3}	

[a] Ref. 1, p. I-85/86, footnote 3.

[b] Ref. 1, p. 63.

[c] Ref. 1, Sect. 5.3.4.1, p. 64.

[d] Ref. 1, Table II 5-8.

[e] Ref. 1, p. II-144.

[f] Ref. 1, p. II-176.

[g] Ref. 1, p. II-90.

[h] Ref. 1, p. 56.

[i] Ref. 1, p. II-405.

[j] Ref. 1, p. II-355.

[k] The *Reactor Safety Study* failure probabilities include a test and maintenance contribution that would not be included in numbers derived from testing. The nontest and maintenance failure probability is 1.3×10^{-2}/D (median) (Ref. 1, p. II-395).

The time on test plot concept, a graphical method of determining an instantaneous failure rate distribution for a particular set of failure data, is described in Appendix D, along with certain precautions in its use in this application. Because of the type of data available in this study, only trends in failure rates were determined using this technique. Total time on test plots for each initiating event and function failure are also included in Appendix D. The results of these plots are summarized in Table 5.2.

5.3 Time Lines For Initiating Events and Function Failures

Time lines were developed to indicate where and when in plant life initiating events and function failures occurred. In addition to demand and potential demand failures, these time lines include short-term maintenance-related function unavailabilities that were not used in the failure probability calculations. Each failure has been identified by NSIC accession number; failure type [demand failure (DF), unavailability and potential demand failure (PDF), or unavailability (U)]; and, for demand and potential demand failures, by severity rating (the concept of severity rating is discussed in Sect. 4.1). Time lines for each item identified in the previous section are included in Appendix E.

5.4 Variation in the Number of Significant Precursors as a Function of Plant Age

The number of significant precursors occurring at different times in plant life were reviewed to determine if a variation as a function of age was apparent. For the reasons discussed in Sect. 4.1, the 47 significant precursors occurring at plants that went critical after January 1, 1969, were used in this determination.

The number of post-1968 significant events per reactor as a function of plant age from criticality is shown in Fig. 5.1. These values are shown as a dot centered in each 200-d period. Only a few plants had long life histories by the end of 1979; thus, the number of observations for the later plant ages is small.* Therefore, the confidence intervals that must be associated with these observations are large. These are shown by the vertical lines passing through each data point. The end points on these lines are 95% confidence intervals under the assumption that the failure data can be modeled using a Poisson distribution.

Because older plants have smaller power ratings, it has been suggested that the decrease in the number of observed events in older plants is influenced more by power level differences than by plant age. This influence is considered small, however, because time on test plots for significant precursors from plants of different power ratings show similar failure rate trends (Fig. 5.2). Because of the apparent lack of influence based on power level, observed differences in the number of events as plant age increased was assumed to be age related.

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*The value of 0.33 at 3700 d corresponds to one observed failure in a period during which only three plants were under observation.

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Table 5.2. Total time on test plot trend indications

Initiating event or demand failure	Failure rate trend[a]
PWR and BWR loss of offsite power	Decreasing
PWR loss of offsite power	Decreasing
BWR loss of offsite power	Constant (perhaps increasing)
PWR small LOCA	Constant (perhaps decreasing)[b]
BWR small LOCA	Decreasing[b]
PWR AFW demand failure	Decreasing
PWR HPI demand failure	Decreasing[b]
PWR long-term core cooling (sump recirculation) demand failure	Constant (perhaps increasing)[b]
PWR emergency power demand failure	Decreasing
PWR steam generator isolation demand failure	Constant[b]
PWR HPI for steam line break mitigation demand failure	Decreasing
BWR HPCI and RCIC demand failure	Decreasing
BWR ADS demand failure	Increasing[b]
BWR emergency power demand failure	Constant (perhaps increasing)
BWR reactor vessel isolation demand failure	Decreasing[b]

[a] See Appendix D for cautions in interpreting these trends.

[b] This conclusion was based on a small number of observed events.

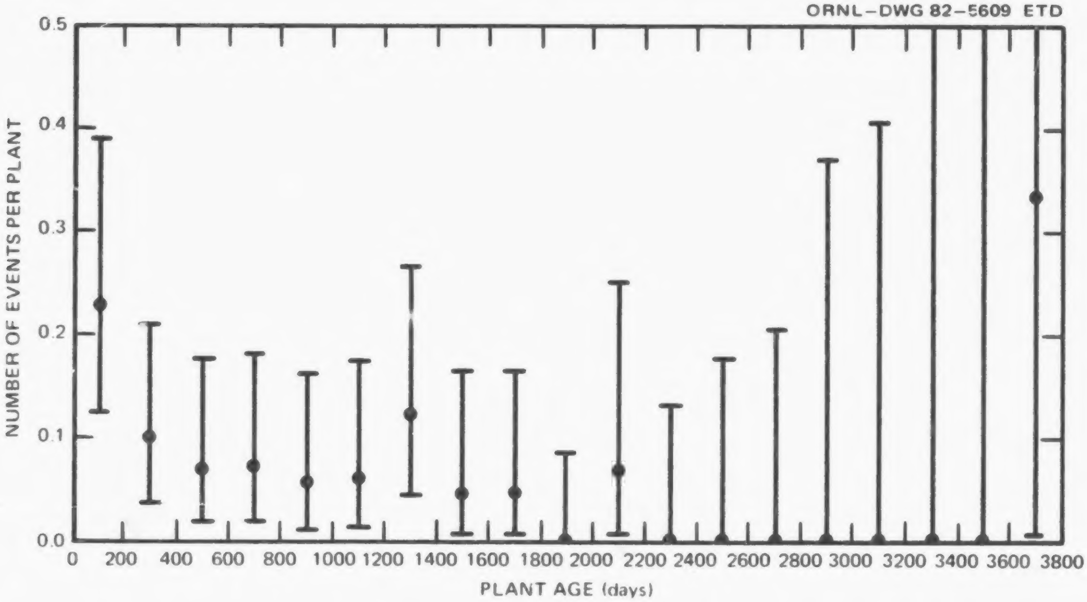

Fig. 5.1. Number of significant precursors per plant as a function of plant age, including confidence limits.

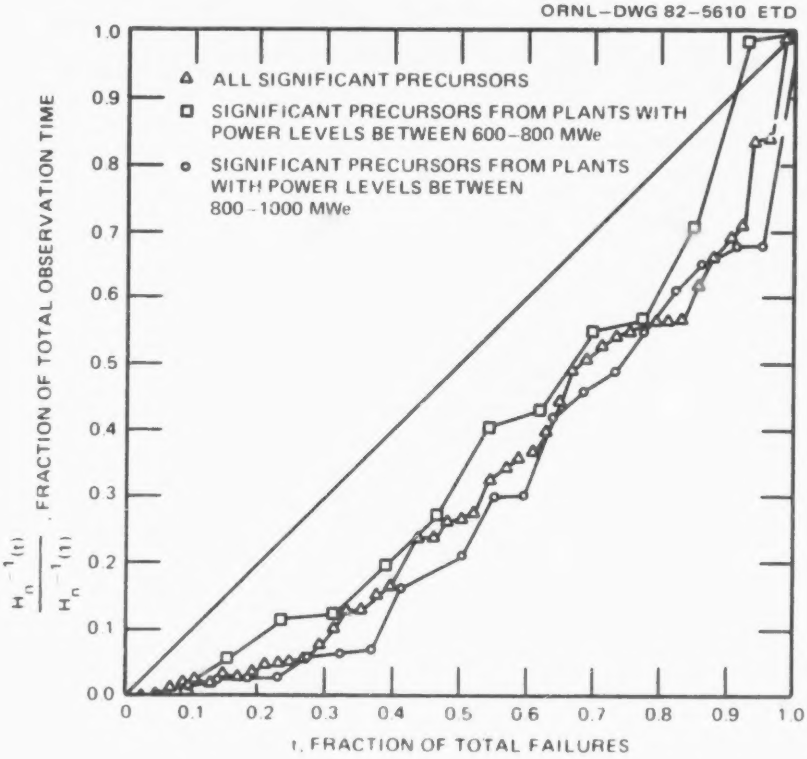

Fig. 5.2. Time on test plot for significant precursors of different power ratings.

[redacted]

However, based on the confidence bounds shown in Fig. 5.1, it was concluded that no clear variation in the number of significant events as a function of plant age had been demonstrated.

5.5 Potential Differences Between Plant Types and Among Vendors, Architect-Engineers, and Plant Power Ratings

Based on the information developed in the previous section, comparisons between reactor types and among vendors, architect-engineers, and plants of different power ratings were performed under the assumption that the number of significant precursor events per reactor plant per unit time is constant, and thus the total number of such events at a plant is proportional to the plant age. As before, only significant events occurring in plants that went critical after 1968 were considered in the comparisons.

These comparisons were performed using chi-square (X^2) tests. The values of X^2 have been calculated both with and without the Yates (−0.5) small number corrections. The results of these comparisons are shown in Table 5.3. The expected number of events in each subcategory was calculated by multiplying the total number of events in each category by the fraction of time since criticality associated with each subcategory. (Criticality dates are identified in the "Grey Books."[2]) As can be seen, no significant differences exist within these categories for plants that went critical after 1968, based on the assumptions used in the tests. Differences would have been considered significant if they had exceeded the associated 95% X^2 value.

5.6 Identification of Degraded-Function Events That Occurred Within 1 Month of Each Significant Precursor

Events reported via the LER system, including degraded functions and initiating events of interest in this study that were not sufficiently serious to be selected as precursors themselves, were identified if they occurred within 1 month of a significant precursor (a 2-month period). This was done to understand what other failures could have been associated with each significant precursor event and to determine if a larger than average number of degraded-function events occurred around the time of significant events. These events are listed in Appendix E. Those degraded-function events that could have had a further impact on significant precursors are listed in Table 5.4.

The following comments are applicable to the identification of degraded-function events:

1. LER events were selected for inclusion in the degraded-function event listings if they resulted in a more than minor degradation of safety-related functions. Events such as minor set-point drift, out-of-specification tank levels, and individual dropped rods were not selected.

Table 5.3. Chi-square tests for differences between plant types and among reactor vendors, architect-engineers, and power levels

	Number of events		Calculated χ^2 values[a]	95% cumulative χ^2 distribution
	Observed	Expected		
Plant type				
PWR	31	27.36	1.15 (0.86)	3.84
BWR	16	19.63		
Reactor vendors				
PWR				
Babcock & Wilcox	10	6.14	3.02 (2.18)	5.99
Combustion Engineering	5	5.94		
Westinghouse	16	18.92		
All				
Babcock & Wilcox	10	5.42	4.58 (3.58)	7.81
Combustion Engineering	5	5.25		
General Electric	16	19.63		
Westinghouse	16	16.70		
Major architect-engineers				
Bechtel	16	15.63	8.90 (5.94)	11.10
Burns and Roe	5	2.58		
Ebasco	7	4.40		
Sargent and Lundy	2	6.96		
Stone and Webster	3	4.71		
United Engineers and Constructors	3	1.73		
Plant power ratings, MWe				
400–600	8	9.76	2.21 (1.15)	7.81
600–800	14	14.49		
800–1000	20	15.61		
1000–1200	5	7.14		

[a] Values given without Yates (−0.5) correction appear first; values with Yates (−0.5) correction are in parentheses.

Table 5.4. Degraded-function events occurring within 1 month of significant percursors that could have had an additional impact on the significant precursor

Significant precursor events				Additional events of interest within 1 month of significant precursor		
NSIC accession No.	Date	Plant	Description	NSIC accession No.	Date	Description
63129	Mar. 24, 1971	La Crosse	Failure of a potential transformer in the switch yard resulted in a LOOP. The shutdown condenser was used to control reactor pressure.	62231	Mar. 24, 1971[a]	During an approach to power, level, flow, and pressure oscillation were encountered, which finally resulted in a reactor scram. The feedwater pump controls were unstable at low flow.
63144	Mar. 8, 1971	Robinson 2	Both DGs failed to run after new low oil pressure switches were remounted on a wall 15 ft from the DGs. Failure to run was traced to the cold, viscous oil and some entrained air in the 1/4-in. line, which prevented pressure buildup within the time limit.	63121	Mar. 14, 1971	Failure of lubrication oil supply to the turbine and generator bearings was caused by inadvertent reduction in battery voltage caused by the continued operation of the dc emergency oil pump following a pump test.
66966	Oct. 10, 1971	Millstone 1	A malfunction in the turbine control system resulted in a turbine trip and a subsequent reactor scram and relief valve operation. The relief valve failed to reset. Insulation around the valve pilot caused the set spring to anneal.		Sept. 17, 1971	During surveillance testing of the LPCI and CS motor-operated valves, the LPCI-1-CP-10B injection valve and the 1-LP-13A torus spray valves failed to operate.
85566	Nov. 19, 1973[a]	Browns Ferry 1	During a complete LOOP test, all offsite power was lost. HPCI and RCIC could not be initiated until ac power was provided by the emergency generators because the resets required ac power.	85750	Nov. 14, 1973	While testing a newly installed switch in the HPCI inverter, the fuse failed on two occasions.
				85738	Nov. 19, 1973[a]	RCIC failed to operate following a 25% LOOP test. HPCI initiated, tripped, was then manually initiated after being reset, and was injected into the reactor vessel.
				87241	Dec. 19, 1973	During a test, DG A could not supply adequate voltage. Its voltage regulator had failed.

Table 5.4 (continued)

Significant precursor events				Additional events of interest within 1 month of significant precursor		
NSIC accession No.	Date	Plant	Description	NSIC accession No.	Date	Description
85738	Nov. 19, 1973[a]	Browns Ferry 1	RCIC failed to operate following a 25% LOOP test. HPCI initiated, tripped, was then manually initiated after being reset, and injected into the reactor vessel.	85750	Nov. 14, 1973	While testing a newly installed switch in the HPCI inverter, the fuse failed on two occasions.
				85566	Nov. 19, 1973[a]	During a complete LOOP test, all offsite power was lost. HPCI and RCIC could not be initiated until ac power was provided by the DGs because the resets required ac power.
89205	Nov. 30, 1973	Surry 1	Reactor coolant pump A shaft failed.	89206	Nov. 30, 1973	Reactor coolant loop B isolation valve shaft failed during cooldown in conjunction with reactor coolant pump A shaft failure.
91676	May 8, 1974	Turkey Point 3	Three AFW pumps failed to start during testing. Two of the three pumps had overtightened packings, and the third had a sticking governor linkage.	93702	Apr. 25, 1974	When unit 4 startup transformers lockout relay was reset while the transformer was isolated for testing and maintenance, current flowed through a sneak circuit and energized unit 4 generator protection relays. This opened generator breakers on both units 3 and 4. Both reactors tripped automatically. A unit 4 safety valve lifted and did not reset until the manual lifting device was removed.
				92449	May 30, 1974[a]	Turbine stop valves failed to close during a normal shutdown because of phosphate buildup between the valve shafts and bushings.
101444	Mar. 22, 1975	Browns Ferry 1	A fire in the cable spreading room resulted in extensive damage.	102267	Apr. 16, 1975	An LPCI injection valve failed to operate electrically during a test. The motor had separated from the valve.
103077	May 1, 1977	Robinson 2	Reactor coolant pump C seal failed.	103199	May 21, 1975	Boric acid transfer pump B failed because of a broken shaft.

Table 5.4 (continued)

Significant precursor events				Additional events of interest within 1 month of significant precursor		
NSIC accession No.	Date	Plant	Description	NSIC accession No.	Date	Description
115870	July 7, 1976	Vermont Yankee	The reactor main steam relief valves were being tested during a refueling outage. The air operators on 3 of 4 valves had failed, rendering the relief valves inoperable. The pilots had been wrapped in insulation, which caused them to overheat and fail.	115721	June 16, 1976	An operator inadvertently drained the pressure reference leg in the vessel water level control system. This resulted in a pressure transient as the feedwater control valves ramped shut and the water level decreased to the scram and ECCS initiation point. HPCI initiated and injected water throughout the transient; however, its gland seal condenser had failed.
115875	June 26, 1976	Haddam Neck	LOOP occurred while switching operations were in progress to restore a line to service because of the incorrect location of a backup protection device with respect to a tie breaker. The reactor was shut down at the time.	116273	July 5, 1976	Both auxiliary feed pumps failed to develop proper discharge pressure because of vapor binding, probably caused by back leakage through a check valve from one of the SGs.
116212	July 20, 1976	Millstone 2	Blown control power fuses discovered after a plant trip on July 5, 1976, resulted in the resetting of the safety-related undervoltage trip set points to ensure all 480 V ac motor control centers would operate at all voltages above the trip set points. On July 20, 1976, a main circulating water pump was started that resulted in an in-plant voltage reduction to below the revised trip set point. This isolated the safety-related buses and started the DGs. However, each time a major load was tied to the diesel, the revised undervoltage trip set points tripped the load. This resulted at the end of the DG loading sequence with the DGs tied to the safety-related buses but with all major loads isolated.	117061	July 24, 1976	The steam-driven AFW pump inlet steam trip valve failed to open because of a sheared shaft. The cause of the shearing was unknown.
				117944	Aug. 10, 1976	A complete LOOP occurred during Hurricane Belle because of severe salt contamination in the plant switchyard.
				117942	Aug. 16, 1976	DG 12U failed to start because of a failed fuel oil servo booster. The booster was cleaned and the diesel returned to the service. The diesel also failed to start for the same reason on Aug. 17 and Aug. 23. A worn leather gasket was finally identified and replaced.
116780	Aug. 10, 1976	Millstone 1	Because of extreme weather conditions, offsite power was lost. The gas turbine, which was running, tripped; however, the DG did start and provided ac power.	116269	July 14, 1976	During surveillance testing, the inboard isolation condenser valve could not be opened, thus rendering the IC inoperable.

Table 5.4 (continued)

Significant precursor events				Additional events of interest within 1 month of significant precursor		
NSIC accession No.	Date	Plant	Description	NSIC accession No.	Date	Description
120293	Nov. 11, 1976	Hatch 1	While the plant was operating at power, all service water strainers were discovered plugged. The backflush motors had tripped. A standing order was given to backflush the strainers twice per shift until the motors could be returned to service.	120290	Nov. 2, 1976	While testing the 1C DG, an overspeed alarm began flashing erratically. The output breaker tripped automatically, and the DG was manually tripped.
				120689	Nov. 29, 1976	The RCIC inverter tripped with the reactor at 84% power. A capacitor in the output transformer had shorted.
123150	Mar. 2, 1977	Crystal River 3	Vital bus B failed because of the failure of inverter B output diode. This caused a reactor trip, turbine trip, and the 30% opening of the atmospheric dump valves. The cooldown rate was 164°F in 15 min.	123781	Mar. 7, 1977	Turbine driven AFW pump 3B tripped on overspeed when started from the control board with main steam as the supply because of a lack of governor response.
				124250	Mar. 22, 1977	Following a reactor trip, manual HPI was initiated on HPI train A. One of the two HPI isolation valves (MUV-24) failed to open because of improper torque switch setting.
128569	July 15, 1977	Brunswick 2	Following a turbine/reactor trip, a relief valve was being used to control reactor pressure. The valve failed to reset because of a ground in the solenoid operator.	120791	June 22, 1977	While HPCI was out of service for repairs and calibration, the 2A RHR pump failed to start during operability test required by Technical Specifications.
130788	Sept. 24, 1977	Davis-Besse 1	A half-trip of the SFRCS due to unknown causes initiated closure of startup feedwater valve FWSP7A. This resulted in reduced water level in SG 2 and subsequent RCS tempera- and pressure rise. The pressurizer PORV lifted 9 times and then stuck open. The valve stuck open because of rapid cycling caused by the omission of a close relay in its control circuit.	130943	Oct. 16, 1977	The governor for AFW pump 1-2 was found closed during testing. The possible cause was excessive vibration from the startup feed pump motor.

Table 5.4 (continued)

Significant precursor events				Additional events of interest within 1 month of significant precursor		
NSIC accession No.	Date	Plant	Description	NSIC accession No.	Date	Description
132927	Nov. 29, 1977	Davis-Besse 1	Generator main breakers were inadvertently opened because of a procedural error shortly after a reactor/turbine trip. This deenergized both 13.8-kV buses. Power was supplied from DG 1-2 in 7 s, and normal offsite power was returned within 11 s on bus B and 25 s on bus A. DG 1-1 failed to supply power to bus C1 because of an overspeed trip.	130942	Nov. 8, 1977	Auxiliary feed pump turbine 1-2 governor vibrated closed because of vibrations from the startup feed pump motor.
				132926	Dec. 6, 1977	Two times within 11 h, two 345-kV air circuit breakers on bus K tripped because of a fault on the Ohio Edison Beaver Line. This deenergized startup transformer 02. The unit was operated on the auxiliary transformer at the time. Cause of the trips was attributed to galloping conductors on the transmission line.
133706	Dec. 11, 1977	Davis-Besse 1	Control over both AFW pumps was lost during testing because of mechanical binding in the governor of one pump and blown control power supply fuses for the speed changer motor on the other pump.	132927, 132929	Nov. 29, 1977	LOOP was caused by procedural error. DG 1-1 tripped on overspeed during starting.
				132926	Dec. 6, 1977	Twice within 11 h, two 345-kV circuit breakers on bus K tripped because of a fault on the Ohio Edison Beaver Line, resulting in the de-energization of startup transformer 02.
				134456	Jan. 6, 1978	AFW pump 1-1 turbine speed control was lost because of the incorrect setting of the high speed stop and the use of improper relays in the control circuits.

Table 5.4 (continued)

Significant precursor events				Additional events of interest within 1 month of significant precursor		
NSIC accession No.	Date	Plant	Description	NSIC accession No.	Date	Description
137543	Apr. 13, 1978	Calvert Cliffs 1	Switchyard breaker protective relaying automatically opened breakers that resulted in loss of all off-site power. DG 11 failed to start and to provide power to 4-kV bus 11. DG 11 was successfully started and loaded about 50 min later. No cause for the DG failure to start was found.	138204	Apr. 10, 1978	DG 12 tripped on overspeed during testing. The cause of the trip was not determined. The diesel was successfully restarted.
				138205	Apr. 10, 1978	DG 12 service water valve failed to open automatically during testing because of a loose positioner feedback spring linkage. The valve was manually opened. [This failure occurred during the same test in which DG 12 tripped on overspeed (see NSIC 138204).]
				138184	Apr. 11, 1978	DG 11 output breaker failed to automatically close following a loss of power on 4-kV bus 11. The breaker was manually closed. (Cause was not determined.) The loss of power on the bus was caused by protective relaying opening breakers in the 500-kV switchyard.
140335	July 28, 1978	Beaver Valley 1	An electrical fault occurred in the station main transformer resulting in generator, turbine, and reactor trip, and safety injection followed 4 min later by LOOP. Both emergency DGs started, but DG 2 failed to flash its field. The field flash failure could not be duplicated.	140209	Aug. 4, 1978	During a load test, the No. 4 station battery charger output breaker tripped before completion of the test. The cause of the trip is unknown.
146744	Jan. 12, 1979	Davis-Besse 1	Loss of power to vital bus Y2 caused by an accidental grounding of a containment hydrogen analyzer resulted in rapid feedwater reduction and increased reactor power and subsequent reactor and SFRCS trip and feedwater isolation.	146690	Jan. 2, 1979	Main steam valves 106 and 106A to AFW pump 1-1 failed to open because of dirt accumulation on the valve stems resulting from construction activity in the area.

Table 5.4 (continued)

Significant precursor events				Additional events of interest within 1 month of significant precursor		
NSIC accession No.	Date	Plant	Description	NSIC accession No.	Date	Description
				148315	Jan. 30, 1979	Main steam code safety valves SP17A2 and SP17B2 lifted below their set point range during plant load swings. Valve SP17A2 was found to have a loose spindle and was gagged. Valve SP17B2 was tested and found satisfactory and returned to service.
149450	May 6, 1979	Oyster Creek	While testing the isolation condenser, a reactor high-pressure scram occurred. The feedwater pump failed to restart and the recirculation pump inlet valves were closed. The reactor water level dropped to the low-low-low level set point. The IC was used during the cooldown.	149235	Apr. 17, 1979	The D recirculation pump was out of service when the C recirculation pump generator collector ring brush was found burned.
				149452	Apr. 19, 1979	During testing of the core spray system, the NZ01A core spray pump failed to start. A fuse was blown in a pump control circuit.
149961	June 3, 1979	Hatch 1	During an LOFW, the HPCI system failed to initiate. Water had contaminated the oil system, preventing the turbine stop valve from opening. RCIC was also inoperable for unspecified reasons.	150117	June 13, 1979	The 13A and B scram discharge volume high-level switches failed to operate during testing. The float switches were binding.
153810	Nov. 20, 1979	Brunswick 1	Following a reactor scram, the RCIC turbine tripped on mechanical overspeed. HPCI was out of service for maintenance. An investigation revealed that a tachometer contact was cracked.	153751	Dec. 7, 1979	While performing a core spray system component test, the "pump running" annunciator was not received. The root valves associated with the instrumentation had been valved out. These switches provide a pump running signal to the ADS system.

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[a] Letter date.

[redacted]

2. LER events were selected for inclusion in the degraded-function event listings based on a reading of the abstract stored in the NSIC computerized data file.

3. Events that were reported at a later date than expected may not have been identified. For events that occurred after 1976, the NSIC abstract contains the date of the event. If the event was reported within the year in which it occurred (or in the next year for significant precursors occurring in November or December), then it would have been identified and considered for inclusion in the degraded-function event listings. However, for events occurring in 1976 and before, only report dates are available in the abstract data base. For significant precursors that occurred in or before 1976, degraded-function events with report dates from 1 month before to 2 months after the precursor event date were identified and selected for possible inclusion in the event listings. The event dates for those degraded-function events selected for possible inclusion were then determined based on a review of the LER itself; if the event occurred within 1 month of the significant precursor, it was selected.

4. As with the selection of events for review as potential precursors, no degraded-function events that occurred prior to criticality were selected.

To serve as a reference for the number of events to be expected within the 2-month period, 39 reference plant and date combinations were selected, and degraded-function events that occurred within 1 month of these dates were identified. The reference plant and dates were selected by choosing an LER at random from the abstract data base and using the plant and event date (or report date when the event date was not available) associated with the LER. This selection method may tend to select reference events associated with plants that have submitted a larger number of LERs and thus may overestimate the number of degraded-function events expected within a 2-month period. The reference degraded-function events are listed in Appendix E.

The distribution in the number of reference observation periods (2-month intervals) that include specific numbers of degraded-function events is shown in Fig. 5.3. The distribution in the number of significant precursor observation periods that include specific numbers of degraded-function events is shown in Fig. 5.4. A comparison of Figs. 5.3 and 5.4 indicates a similar distribution, with the exception of a "tail" associated with the significant precursor distribution. No statistical analyses have been performed on these distributions.

5.7 Percentage of Precursors Involving Human Error

Precursors that involved human error are identified in the computerized precursor listings (Tables 3.1 and 4.2). The determination of whether human error was involved was based on a review of the detailed event and not on whether human error was specifically reported in an LER. Human errors of interest are errors in operations and maintenance that significantly affect the precursor event. The percentage of precursors that

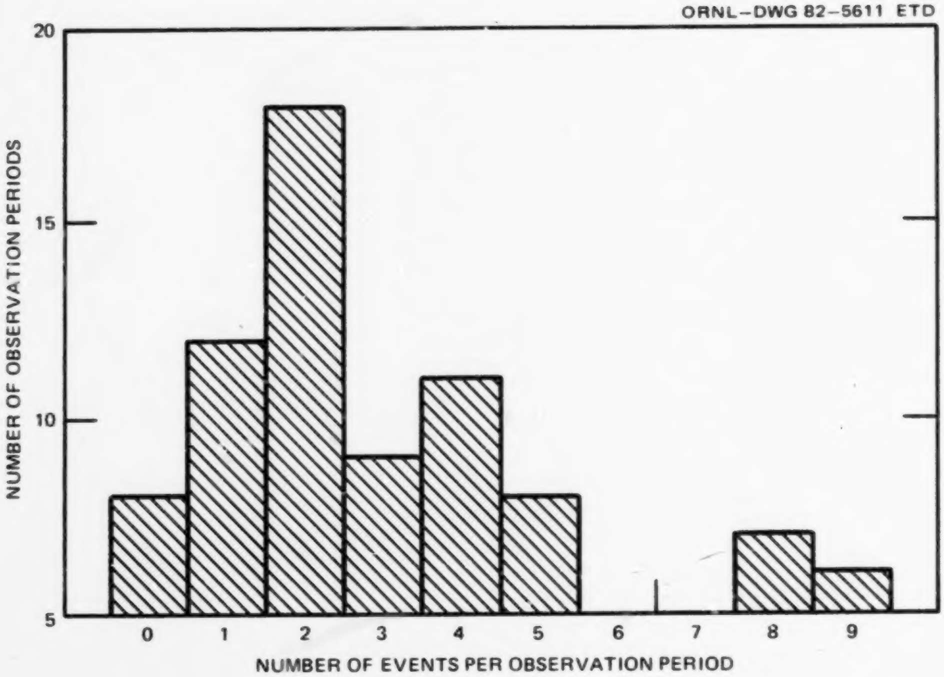

Fig. 5.3. Number of degraded-function events of interest observed within 1 month of 39 reference date and plant combinations.

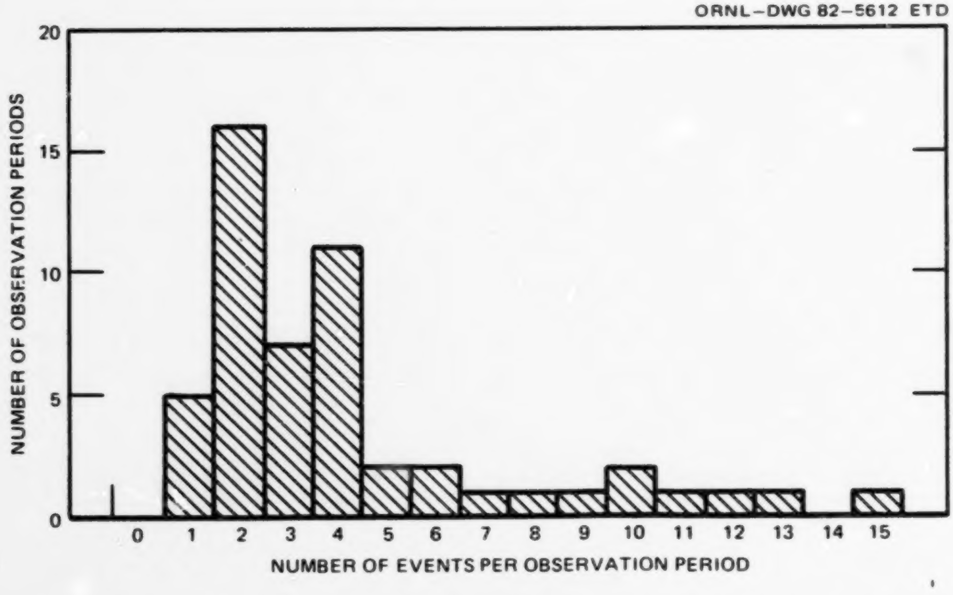

Fig. 5.4. Number of degraded-function events of interest observed within 1 month of 52 significant precursors.

involved human error are listed below and compared with the percentage of all LERs pertaining to safety-related systems involving human error in 1979:

Event type	Events involving human error (%)
Significant precursors	38
All precursors	36
1979 safety-related LERs*	29

5.8 Estimation of the Probability of a Diesel Generator Failing to Start Given a Loss-of-Offsite-Power Demand

All losses of offsite power that occurred between 1969 and 1979 and were reported via the LER system were reviewed as precursors. Subsequent to the precursor probability measure and significance calculations, it became apparent that a larger than expected number of diesel generator failures to start or load had occurred during actual losses of offsite power. Because of this, the number of diesels that failed during a loss of offsite power was determined and the individual diesel failure-to-start probability was estimated.

In the population of reactors that went critical after 1968, 33 losses of offsite power reported via the LER system were selected as precursors. In these events, emergency power source failures to start were reported as shown in Table 5.5. These events are described in Appendix B. Of these events, NSIC 116780 involved the failure of a gas turbine generator, and NSIC 139565 involved the failure of a diesel to start while undergoing maintenance when the reactor was in cold shutdown. NSIC 61565 and NSIC 152951 involved failures that were quickly rectified by the operator. Using the same failure-severity approach as was used in the determination of function failure probabilities (see Sect. 4.1) and excluding the St. Lucie and Millstone 1 failures, the number of diesel generator failures to start given a loss of offsite power is 4.2. The actual number of diesel generators demanded during these losses of offsite power is 66. This results in a failure probability estimate given a true LOOP of 0.064 per demand.

The emergency power demand failure probability initially determined in this study and used in the probability calculations was estimated based

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*Compiled from tables in two reports by R. L. Scott and R. B. Gallaher: *Summary and Bibliography of Safety-Related Events at Pressurized-Water Nuclear Power Plants as Reported in 1979*, NUREG/CR 1613 (July 1981), Table 4, and *Summary and Bibliography of Safety-Related Events at Boiling Water Reactor Plants as Reported in 1979*, NUREG/CR-1612 (June 1981), Table 4.

Table 5.5. Emergency power source failures to start during a LOOP

NSIC accession No.	Plant	Date of event	Severity rating[a]
61565	Palisades	Sept. 2, 1971	0.1
116780	Millstone 1	Aug. 10, 1976	
132927	Davis-Besse 1	Nov. 29, 1977	1
137543	Calvert Cliffs 1	Apr. 13, 1978	1
139565	St. Lucie	May 14, 1978	
140335	Beaver Valley 1	July 28, 1978	1
152187	St. Lucie	Sept. 3, 1979	1
152951	Davis-Besse 1	Oct. 15, 1979	0.1

[a] See Sect. 4.1 for definition of severity rating.

on the number of total emergency power function failures and unavailabilities observed in the LER data. This estimate was 1.8×10^{-3}/D for PWRs and 5.0×10^{-3}/D for BWRs. The per-diesel demand failure probability calculated in this section, if used to estimate a total function failure probability, would result in an estimate that is higher (for PWRs) than that previously determined, even if diesel generator failures are assumed to be independent. This discrepancy deserves further investigation.

The trend analyses provided in this section are not considered all encompassing, nor have they involved extreme statistical sophistication. They were a first attempt to determine if trends were discernible in the selected precursors and are examples of the information that can be reasonably extracted from the kind of operating experience data currently available.

References

1. U.S. Nuclear Regulatory Commission, *Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants*, WASH-1400 (NUREG-75/014)(October 1975).

2. U.S. Nuclear Regulatory Commission, *Operating Units Status Reports — Licensed Operating Reactors*, NUREG-0020, published monthly.

Appendix A

STANDARDIZED EVENT TREES

Standardized functional event trees were constructed to describe the mitigation sequences for four initiating events used in the study: loss of main feedwater, loss of offsite power, small loss-of-coolant accident, and steam line break. These standard sequences were used with the majority of events selected as precursors. Certain events could not be described using the standard trees developed in this appendix. In such cases, unique event trees were developed to describe the sequences of interest. The four standard sequences are considered separately for PWRs and BWRs. As discussed in the main report, the first two events are considered to be the most likely off-normal events of concern and the latter two represent bounding events for many of the safety-related systems in a reactor plant.

This appendix (1) describes the mitigation sequences utilized for the four initiating events, (2) identifies the combinations of functions required for the successful mitigation of each initiator, and (3) describes the criteria for success of each function in general terms.

The event tree associated with each mitigation sequence is constructed with function success as the upper branch and function failure as the lower branch. Each sequence path is read from left to right. As an example, a point in a sequence of events involving a PWR loss of main feedwater, a successful reactor trip, and a failure of auxiliary feedwater and secondary heat removal would be located at point A on the event tree shown in Fig. A.1.

A.1 PWR Loss of Main Feedwater

A functional event tree was constructed to define a representative response of PWRs to a loss of main feedwater in terms of the success or failure of critical safety functions. The event tree shown in Fig. A.2 includes the normal mitigation sequence for a loss of main feedwater: reactor trip and auxiliary feedwater initiation. The tree also includes (1) the use of high-pressure injection to prevent severe core damage if auxiliary feedwater is unavailable and (2) mitigation sequences for a failure to trip and for a relief valve that does not reseat following a lift after a loss of main feedwater. The event tree functions and the sequences leading to potential severe core damage follow.

1. Initiating event (loss of main feedwater). The initiating event for the tree is a loss of main feedwater to the extent that reactor trip is required.

2. Reactor trip. Reactor trip success is defined as the rapid insertion of sufficient control rods to place the core in a subcritical condition for the short term (while the reactor is maintained in a hot shutdown condition).

ORNL-DWG 82-5544 ETD

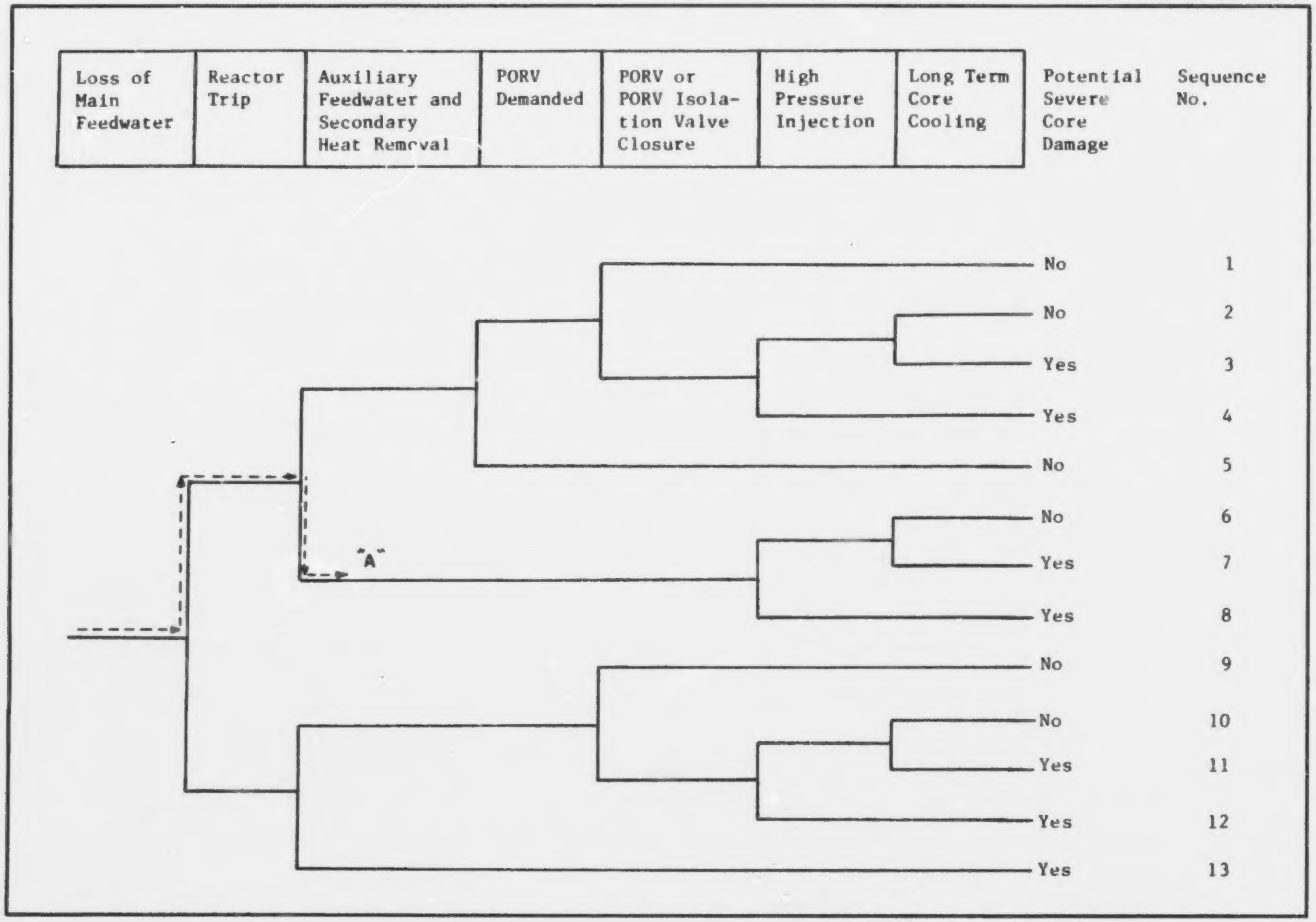

Loss of Main Feedwater
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
"A"
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

Fig. A.1. PWR standard event tree for loss of main feedwater with successful reactor trip and failed auxiliary feedwater and secondary heat removal.

ORNL-DWG 82-5545 ETD

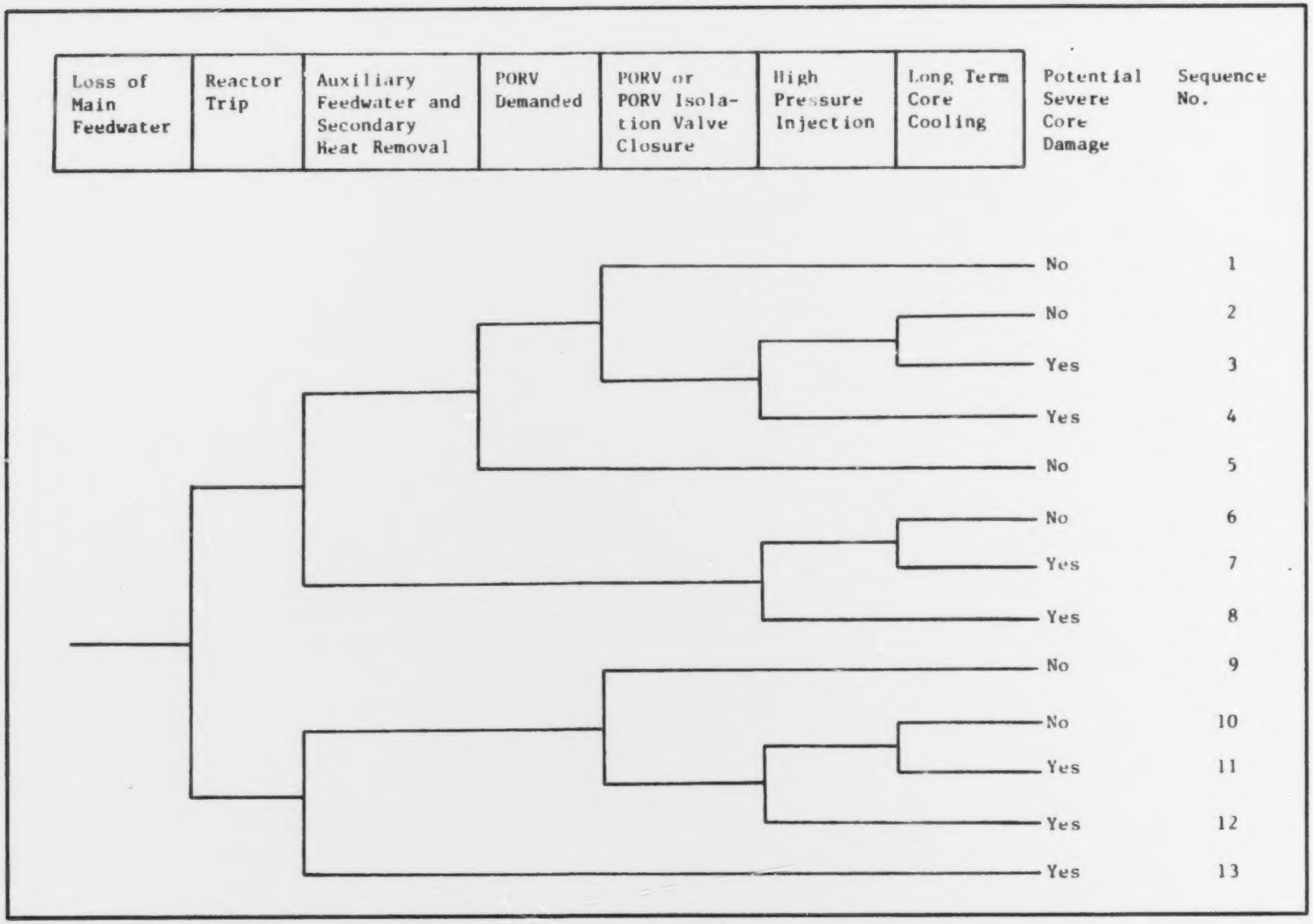

Loss of Main Feedwater
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

Fig. A.2. Standard event tree for PWR loss of main feedwater.

[redacted]

3. Auxiliary feedwater and secondary heat removal. Success requirements for this function depend on whether or not reactor trip has been successful. In either case, sufficient auxiliary feedwater must be provided to remove the heat still being generated in the reactor coolant system via the steam generators and secondary side relief valves, atmospheric dump valves, and turbine bypass valves.

If reactor trip has been successful, auxiliary feedwater success usually requires flow to one or more steam generators from one train of a redundant auxiliary feedwater system over a period of time, perhaps 12-24 h.

If reactor trip has not been successful, then rapid injection of copious quantities of auxiliary feedwater may prevent excessive RCS pressures on some plants. The detailed requirements for successful auxiliary feedwater initiation following a failure to trip are still under discussion between the NRC and the reactor vendors, as are other plant changes that may be required for such an event. Because of this discussion of requirements, it is not possible in all cases to accurately distinguish between a failed and a degraded auxiliary feedwater system when reactor trip is unsuccessful. The event tree for a loss of main feedwater has been constructed to include the use of auxiliary feedwater following failure to trip to prevent core damage.

4. Pilot-operated relief valve demanded. For the case where both reactor trip and auxiliary feedwater initiation has been successful following a loss of main feedwater, the pressurizer pilot-operated relief valve (or valves) may or may not lift, depending on the peak pressurizer pressure following the transient. The upper branch for this function merely indicates that the valve or valves were demanded because of the peak pressure during the transient. It is assumed, because of the multiplicity of relief and safety valves, that a sufficient number will open if required for this case, as the peak pressures are not particularly high.

The lower branch indicates that the pressurizer pressure was not sufficiently high to require opening of a relief valve. For the cases in which (1) auxiliary feedwater fails following reactor trip success or (2) reactor trip fails, at least one pressurizer relief valve is assumed to be demanded.

5. PORV or PORV isolation valve closure. Success for this function requires the closure of any open relief valve once pressurizer pressure has decreased below the relief valve set point. In the case of pilot-operated relief valves, an isolation valve is usually provided adjacent to the valve to permit manual termination of relief valve blowdown if the valve sticks open.

6. High-pressure injection. For the case in which reactor trip is successful following a loss of main feedwater but the auxiliary feedwater and secondary heat removal function is unsuccessful, high-pressure injection may be used on some plants to provide adequate core cooling. In such a case, borated water is injected via the high-pressure injection system and discharged to the containment via the pressurizer relief valves. Depending on the design of a plant's high-pressure injection system, a PORV may have to be manually opened at a pressure considerably below its normal set point.

Success for this function is very dependent on plant design but generally requires the introduction of sufficient amounts of borated water into the reactor coolant system to remove decay heat and prevent severe core damage.

7. Long-term core cooling. Auxiliary feedwater and secondary heat removal functional success was considered to satisfy the need for core cooling for the purposes of this study. If auxiliary feedwater and secondary heat removal was not completely successful, either because the function failed or because a PORV remained open, then the requirement for long-term core cooling (following injection of available borated water supplies) was considered satisfied by using high-pressure injection in the recirculation mode.

Because of the long-term nature of this function and the reduced heat load during its operation, the possibility of component repair and the use of alternate methods becomes much more likely. As such, a definition of function success in terms of specific system and component operability, except during the initial period, is not particularly useful. For this study, HPI recirculation was considered to be required during the initial phases of long-term cooling.

8. Loss of main feedwater sequences resulting in potential severe core damage. Seven of the thirteen sequences identified for a loss of main feedwater were considered to result in potential severe core damage. These sequences are

- failure of long-term core cooling after a PORV is demanded and fails to close (sequences 3 and 11);
- failure of high-pressure injection following failure of a demanded PORV or its isolation valve to close (sequences 4 and 12);
- failure of long-term core cooling following high-pressure injection success, auxiliary feedwater failure, and reactor trip success (sequence 7);
- failure of high-pressure injection following auxiliary feedwater failure and reactor trip success (sequence 8);
- failure of auxiliary feedwater following failure of reactor trip (sequence 13).

A.2 PWR Loss of Offsite Power

A functional event tree was constructed to define a representative response of PWRs to a loss of offsite power in terms of success or failure of critical safety functions. A loss of offsite power without turbine runback will result in reactor trip due to unavailability of power to the CRDMs and a loss of main feedwater due to unavailability of power to components in the condensate or condenser cooling systems.

The event tree shown in Fig. A.3 includes the normal mitigation sequence for a loss of offsite power: turbine runback, if available and

ORNL-DWG 82-5546 ETD

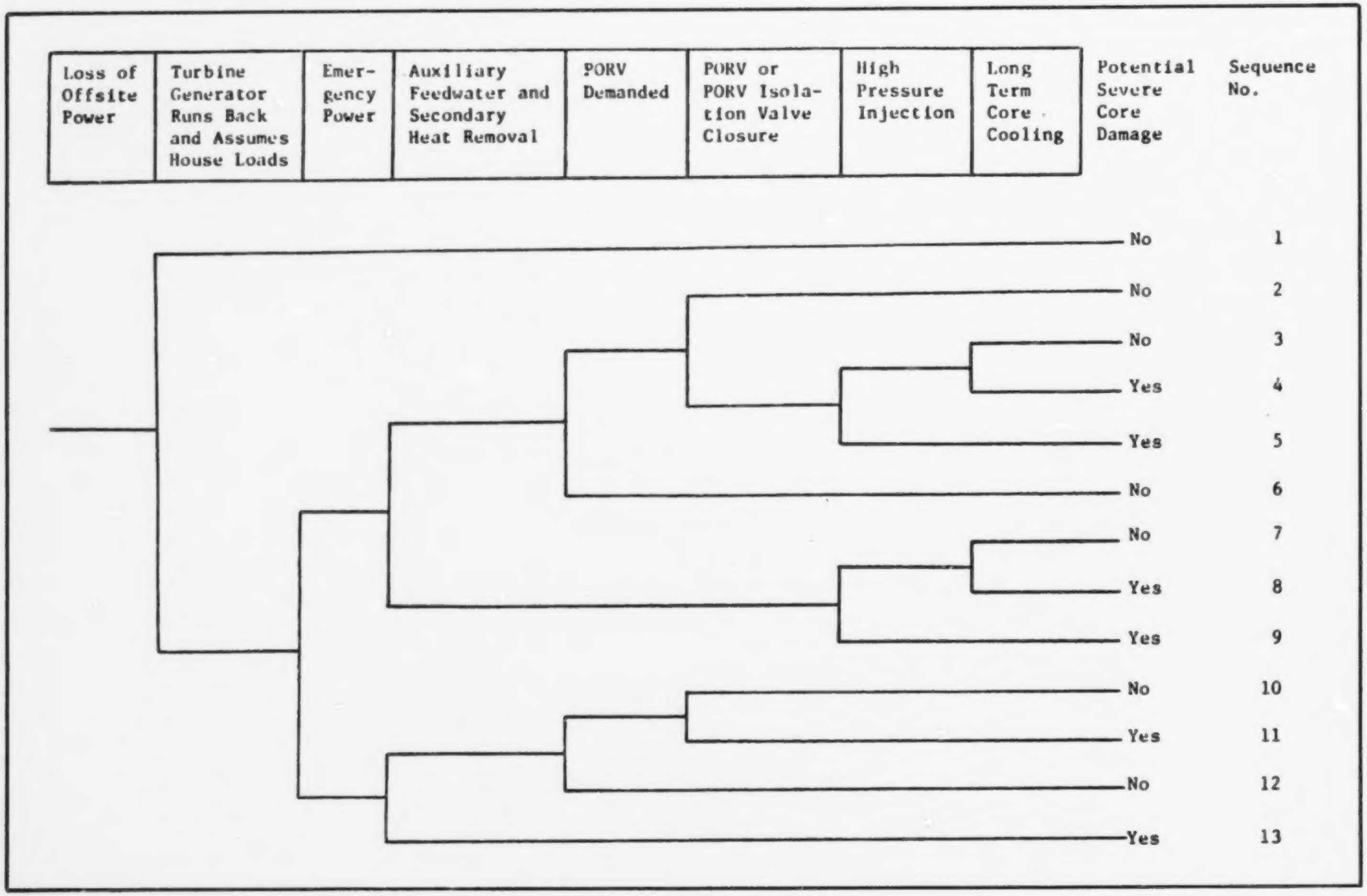

Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

Fig. A.3. Standard event tree for PWR loss of offsite power.

successful and, if not, emergency power initiation and the mitigation sequence discussed previously for a loss of main feedwater. The event tree functions and the sequences leading to potential severe core damage follow.

1. Initiating event (loss of offsite power). The initiating event for the tree is a grid or switchyard disturbance to the extent that the generator must be separated from the grid and all offsite power sources are unavailable to plant equipment.

2. Turbine generator runs back and assumes house loads. On certain plants the capability of a runback from full power to house loads (~10% power) is provided in the event the generator must be separated from the grid. Success for this function would be such a successful runback and continued maintenance of in-plant electric loads from the unit generator.

3. Emergency power. If a turbine runback is not successful, then electric power would be lost to all loads not backed by battery power when the unit generator trips. Reactor trip would occur at this time (because of the loss of power to the CRDMs) if it did not occur earlier due to conditions in the reactor coolant system. When power is lost, diesel generators are automatically started to provide power to the plant safety-related loads. Emergency power success requires the starting and loading of a sufficient number of diesel generators to support safety-related loads in systems required to mitigate the transient and maintain the plant in a safe shutdown condition.

4. Auxiliary feedwater and secondary heat removal. Success requirements for this function are equivalent to those following a loss of main feedwater with a subsequent reactor trip. However, since specific auxiliary feedwater systems may contain either turbine-driven or motor-driven pumps, the capability of the system to meet its success requirements will in many cases also be dependent on the success or failure of the emergency power function.

5. Pilot-operated relief valve demanded. The upper and lower branches for this function are similar to those following a loss of main feedwater with a subsequent reactor trip.

6. PORV or PORV isolation valve closure. The success requirements for this function are similar to those following a loss of main feedwater.

7. High-pressure injection. The success requirements for this function are similar to those following a loss of main feedwater. However, because all high-pressure injection systems utilize motor-driven pumps, the capability of the high-pressure injection function to meet its success requirements is dependent on the success of the emergency power function.

8. Long-term core cooling. The success requirements for this function are similar to those following a loss of main feedwater. Because all systems used for long-term cooling utilize motor-driven pumps, function success is dependent on the success of the emergency power function.

9. Loss of offsite power sequences resulting in potential severe core damage. Six of thirteen sequences identified for a loss of offsite power are considered to result in potential severe core damage. These sequences are

- failure of long-term core cooling after a PORV is demanded and fails to close (sequences 4 and 11),
- failure of high-pressure injection following failure of a demanded PORV or its isolation valve to close (sequence 5),
- failure of long-term core cooling following high-pressure injection success and auxiliary feedwater failure (sequence 8),
- failure of high-pressure injection following auxiliary feedwater failure (sequence 9),
- failure of auxiliary feedwater and emergency power (sequence 13).

A.3 PWR Small Loss-of-Coolant Accident

A functional event tree was constructed to define a representative response of PWRs to a small LOCA in terms of success or failure of critical safety functions. The LOCA chosen for consideration is one that would require a reactor trip and continued high-pressure injection for core protection. Because of the limited amount of borated water available for initial injection, the mitigation sequence also includes the capability of providing borated water from the containment sump (usually via the low-pressure recirculation system) to the high-pressure injection pump suctions.

The event tree is shown in Fig. A.4, and functions and sequences leading to potential severe core damage follow.

1. Initiating event (small LOCA). As described previously, the initiating event for the tree is a small LOCA that requires reactor trip and high-pressure injection for core protection.

2. Reactor trip. Reactor trip success is defined as the rapid insertion of sufficient control rods to place the core in a subcritical condition.

3. Auxiliary feedwater and secondary heat removal. If reactor trip is not successful, then rapid injection of auxiliary feedwater may prevent core damage, as in the case of the loss of main feedwater. To an even greater extent than was the case with the loss-of-main-feedwater transient, the detailed requirements for auxiliary feedwater success following a LOCA and a failure to trip have not been determined. Because of this, it is not always possible to distinguish between a failed and a degraded auxiliary feedwater system for the case in which reactor trip has not been successful.

Certain small breaks may require auxiliary feedwater even with reactor trip success, particularly if high-pressure injection is only minimally successful. This has not been considered in the representative event tree.

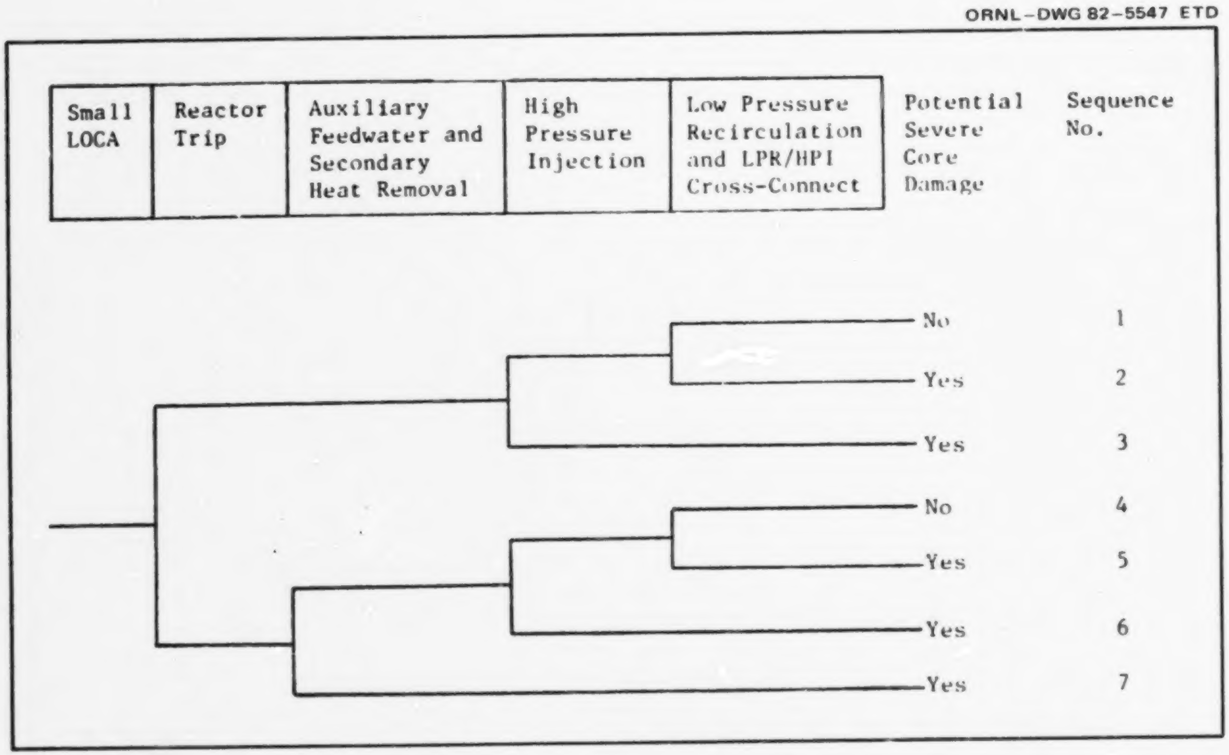

ORNL-DWG 82-5547 ETD
Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
No
1
Yes
2
Yes
3
No
4
Yes
5
Yes
6
Yes
7

Fig. A.4. Standard event tree for PWR small loss-of-coolant accident.

4. High-pressure injection. Success for this function requires adequate injection of borated water to prevent excessive core temperatures and consequent damage. The adequacy of redundant portions of the high-pressure injection system and its associated support systems in performing this function is confirmed in each plant's safety analyses.

5. Low-pressure recirculation and LPR/HPI cross-connect. The HPI system takes suction from a tank of borated water during the initial stages of the LOCA mitigation sequence. This water is subsequently spilled from the break and collects on the containment floor and in the containment sump. Success for this function requires delivery of sump water to the suctions of the high-pressure pumps to provide continued injection of borated water. This is usually provided via the low-pressure injection system realigned to take suction from the containment sump. In this manner, continued core cooling can be achieved with a limited initial volume of borated water. Because of the long-term nature of this function, the possibility of component repair (at least for support systems) and the use of alternate methods becomes more likely, and a rigid definition of function success in terms of specific system operability is difficult.

6. Small LOCA sequences resulting in potential severe core damage. Five of the seven sequences identified for a small LOCA are considered to result in potential severe core damage. These sequences are

- failure of low-pressure recirculation and LPR/HPI cross-connect (sequences 2 and 5),
- failure of high-pressure injection (sequences 3 and 6),
- failure of auxiliary feedwater following failure to trip (sequence 7).

A.4 PWR Steam Line Break

A functional event tree was constructed to define a representative response of PWRs to a steam line break in terms of success or failure of critical safety functions. The event tree shown in Fig. A.5 includes the normal mitigation sequence for a steam line break: reactor trip, steam generator isolation, use of auxiliary feedwater for reactor cooling following isolation of the break, and high-pressure injection of borated water for additional shutdown margin if required. The tree also includes a mitigation sequence for a relief valve that does not reseat following a lift due to continued high-pressure injection. Event tree functions and the sequences leading to potential severe core damage follow.

1. Initiating event (steam line break). The initiating event for the tree is a steam line break of the extent that reactor trip is required. The break in question is usually larger than one stuck-open relief or dump valve and may require isolation of the affected steam generator.

ORNL–DWG 82–5548 ETD

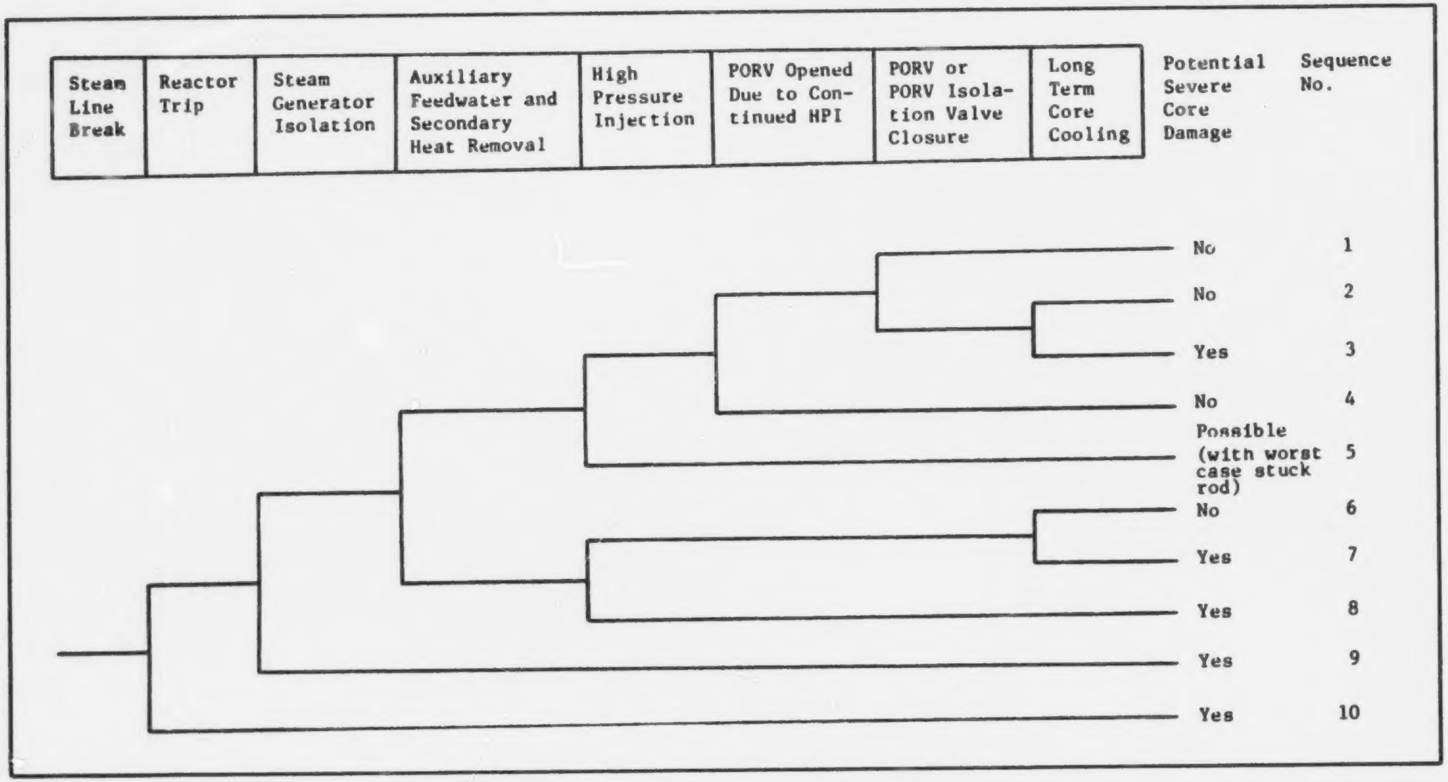

Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

Fig. A.5. Standard event tree for PWR steam line break.

[redacted]

2. Reactor trip. Reactor trip success is defined as the rapid insertion of sufficient control rods to reduce core power to a level at which core damage will not occur and which can be reduced to subcritical, if not already subcritical, through the subsequent high-pressure injection of borated water.

Because of the excessive heat removal associated with a steam line break, failure to trip will result in excessive power levels and thus potential severe core damage.

3. Steam generator isolation. Steam generator isolation success requires the termination of feedwater to the affected steam generator and isolation of unaffected steam generators from the steam line break. This limits steam generator blowdown to the inventory in the affected steam generator. Failure to isolate the affected steam generator after a steam line break may result in excessive cooldown and consequent potential severe core damage due to overpower, even if trip occurs, depending on the size of the break and the specific plant.

4. Auxiliary feedwater and secondary heat removal. After reactor trip and steam generator isolation, injection of auxiliary feedwater into an operable steam generator is required for continued core cooling. Success requirements for this function are similar to those following a loss of main feedwater with a subsequent reactor trip, with the additional requirement that auxiliary feedwater be provided only to operable steam generators.

5. High-pressure injection. Success for this function requires injection of sufficient borated water to place the core in a subcritical condition if it remains at power following trip. This could be the case at some plants if the most reactive control rod assembly does not enter the core.

In the event auxiliary feedwater fails to function following steam generator isolation, the high-pressure injection function may provide continued core cooling in a manner similar to that following a loss of feedwater. In this case, the requirements for high-pressure injection success would be similar to those for a loss of main feedwater with subsequent reactor trip and auxiliary feedwater failure.

6. Pilot-operated relief valve opened due to continued HPI. High-pressure injection is automatically initiated following detection of a steam line break. In many cases for plants with HPI capability above the pressurizer relief valve set points, continued HPI system operation is expected to result in a PORV lift. The upper branch for this function indicates that such a valve opened because of pressurizer pressure during mitigation.

The lower branch for this function indicates that high-pressure injection was secured prior to PORV lift. For the case in which high-pressure-injection success provides continued core cooling following loss of auxiliary feedwater, at least one pressurizer relief valve is assumed to open or be opened.

7. PORV or PORV isolation valve closure. Success requirements for this function are similar to those following a loss of main feedwater.

8. Long-term core cooling. The success requirements for this function are similar to those following a loss of main feedwater.

9. Steam line break sequences resulting in potential severe core damage. Six of ten sequences identified for a steam line break are considered to result in potential severe core damage. These sequences are

- failure of long-term core cooling if a PORV is demanded and fails to close (sequences 3 and 7);
- failure of high-pressure injection provided a high reactivity control assembly sticks out (sequence 5);
- failure of high-pressure injection following a failure of auxiliary feedwater (sequence 8);
- failure to isolate the affected steam generator (sequence 9) (although this has been assumed for all steam line breaks in this study, potential severe core damage may only occur following a failure of steam generator isolation for large breaks);
- failure to trip (sequence 10).

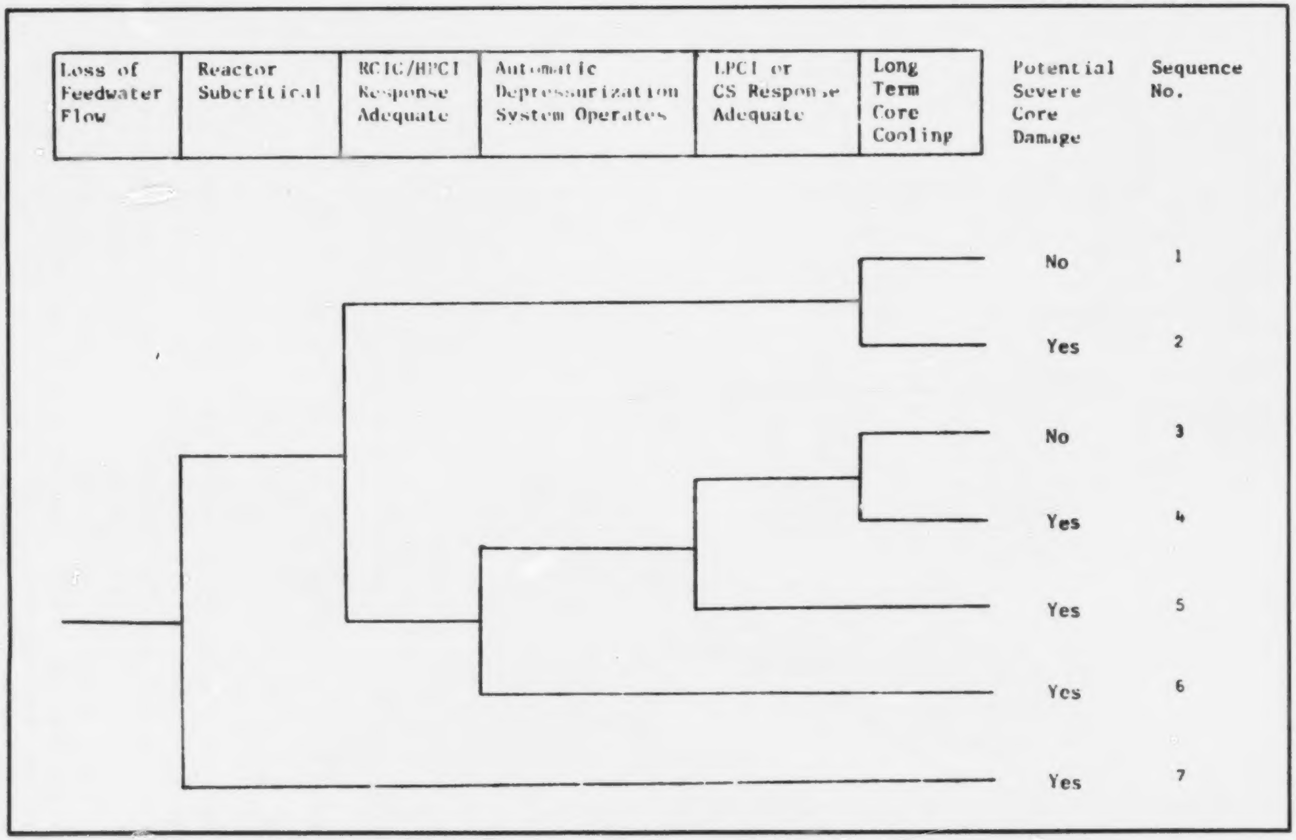
A.5 BWR Loss of Main Feedwater

A functional event tree was constructed to identify a representative response of BWRs to a loss of main feedwater in terms of success or failure of critical safety functions. The normal mitigation sequence for this event, reactor scram and RCIC initiation, is illustrated in Fig. A.6. Also presented are alternative methods of providing adequate core cooling: high-pressure coolant injection and the low-pressure systems, which rely on automatic depressurization for initiation. Event tree functions and the sequences leading to potential severe core damage follow.

1. Initiating event (loss of main feedwater). Any trip of both reactor feed pumps, except trips induced by loss of offsite power, is considered an initiating event for the tree.

2. Reactor subcritical. Once the main feedwater pumps trip, flow to the reactor will decay to zero in about 5 s. The reduction in main feedwater is sensed, and the recirculation pumps are automatically throttled back, resulting in a negative insertion of reactivity. Without makeup water, the water level will drop in the reactor as coolant is boiled off. When the low-level set point is reached, a scram is initiated. The operator has two shutdown options available if scram fails:

- Control rods not successfully inserted during scram can be manually actuated. All but two adjacent control rods must be inserted within 30 min of the scram signal.


ORNL-DWG 82-5549 ETD

Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
No
1
Yes
2
No
3
Yes
4
Yes
5
Yes
6
Yes
7

Fig. A.6. Standard event tree for BWR loss of feedwater.

[redacted]

- Reactor recirculation pumps must be tripped in conjunction with the successful operation of the standby liquid control system. The SBLC system must be initiated within 10 min after the failure to scram, and the core must be subcritical within 38 min after the failure to scram.

A successful scram or either of the above methods is sufficient to reduce the reactor thermal output to the decay heat level.

If poisoning of the neutron chain reaction is not adequate to cause reactor shutdown within a given time frame, the potential for severe core damage exists.

3. RCIC/HPCI response adequate. Success requirements for this function are satisfied on initiation and operation of reactor core isolation cooling. However, both the RCIC and HPCI initiate when the reactor coolant inventory drops to the low-low-level set point. Thus, the operator must secure HPCI when pressure and water level control are restored. Failure to secure HPCI could result in tripping both RCIC and HPCI turbine pumps on high water level. RCIC must be operated until the residual heat removal system can be placed into service. In the event of a failure of RCIC, HPCI may be used to provide reactor makeup water.

Following reactor trip, reactor pressure will increase until the lowest set point of the electromatic relief valves is reached. These valves will open and close periodically to maintain reactor pressure control. RCIC has the capacity to maintain water level control if one relief valve fails to reset. If additional valves remain open, HPCI operation is necessary.

Some older BWRs are equipped with isolation condensers instead of RCIC. The ICs use natural circulation; their success depends on the opening of dc-powered valves, a sufficient flow path from the annulus to the core region once the IC is initiated, and sufficient coolant on the shell side of the IC heat exchanger to ensure adequate heat transfer. The majority of BWRs equipped with ICs also rely on the feedwater pumps for high-pressure injection.

4. Automatic depressurization system operates. If RCIC and HPCI fail to provide adequate flow to maintain reactor level control, the low-pressure high-capacity systems can be used to maintain level control. However, for these systems to operate, pressure must be reduced to the system's operating range. This is accomplished by the automatic depressurization system, which can be manually or automatically initiated. Automatic initiation success requires high dry-well pressure, low-low-low reactor water level, and the availability of one train in either of the low-pressure high-capacity systems. Given this state, the ADS will autoinitiate after a time delay.

5. LPCI or CS response adequate. Given the need and successful operation of ADS, the low-pressure coolant injection or core spray can be used to ensure adequate core cooling. Success requires operation of one train of either of the systems.

6. Long-term core cooling. Success of this function requires that heat transfer to the environment commence within about 1 d. Successful

delivery of cooling water to the RHR heat exchanger satisfies this function. However, because of the long-term nature of this function, the possibility of component repair and the use of alternate methods becomes more likely, and defining function success in terms of specific system and component operability is difficult.

Normally the RHR system provides for long-term core cooling. However, as discussed previously, its failure may not, under all circumstances, constitute a failure of the long-term cooling function. For example, during the Browns Ferry fire a combination of safety valves, control rod drive pumps, and the condensate and condensate booster pumps were used for several hours to maintain core cooling until normal means could be restored. Cross ties frequently exist in multiple unit plants and allow operable systems in one unit to provide for the failed function in another unit.

7. Loss-of-main-feedwater sequences resulting in potential severe core damage. Five of the seven sequences identified are considered to result in potential severe core damage. These sequences are

- failure of long-term core cooling given success of the emergency core cooling systems (RCIC/HPCI/CS/LPCI) (sequences 2 and 4),
- complete failure of emergency core cooling systems (RCIC/HPCI/CS/LPCI) (sequence 5),
- failure of high-pressure coolant injection and automatic depressurization (sequence 6),
- failure to shut down the reactor in a sufficient time period (sequence 7).

A.6 BWR Loss of Offsite Power

The functional event tree for a loss of offsite power is illustrated in Fig. A.7. The normal mitigating sequence is reactor scram and initiation and operation of the RCIC. Other available paths are reactor scram and HPCI or reactor scram and ADS/LPCI/CS.

A LOOP condition would result in a generator load rejection that trips the turbine control valve and results in a scram. Event tree functions and the sequences leading to potential severe core damage follow.

1. Initiating event. The initiating event for LOOP corresponds to any situation in which power from both the auxiliary and startup transformers is lost. This situation could result from grid disturbances or onsite faults.

2. Reactor scram. As previously mentioned, a scram signal is generated given a load rejection. A successful scram is taken to be a rapid insertion of control rods with no more than two adjacent control rods failing to insert.

3. Diesel starts and loads. The diesel generators receive an initiation signal when an undervoltage condition is detected. The diesel

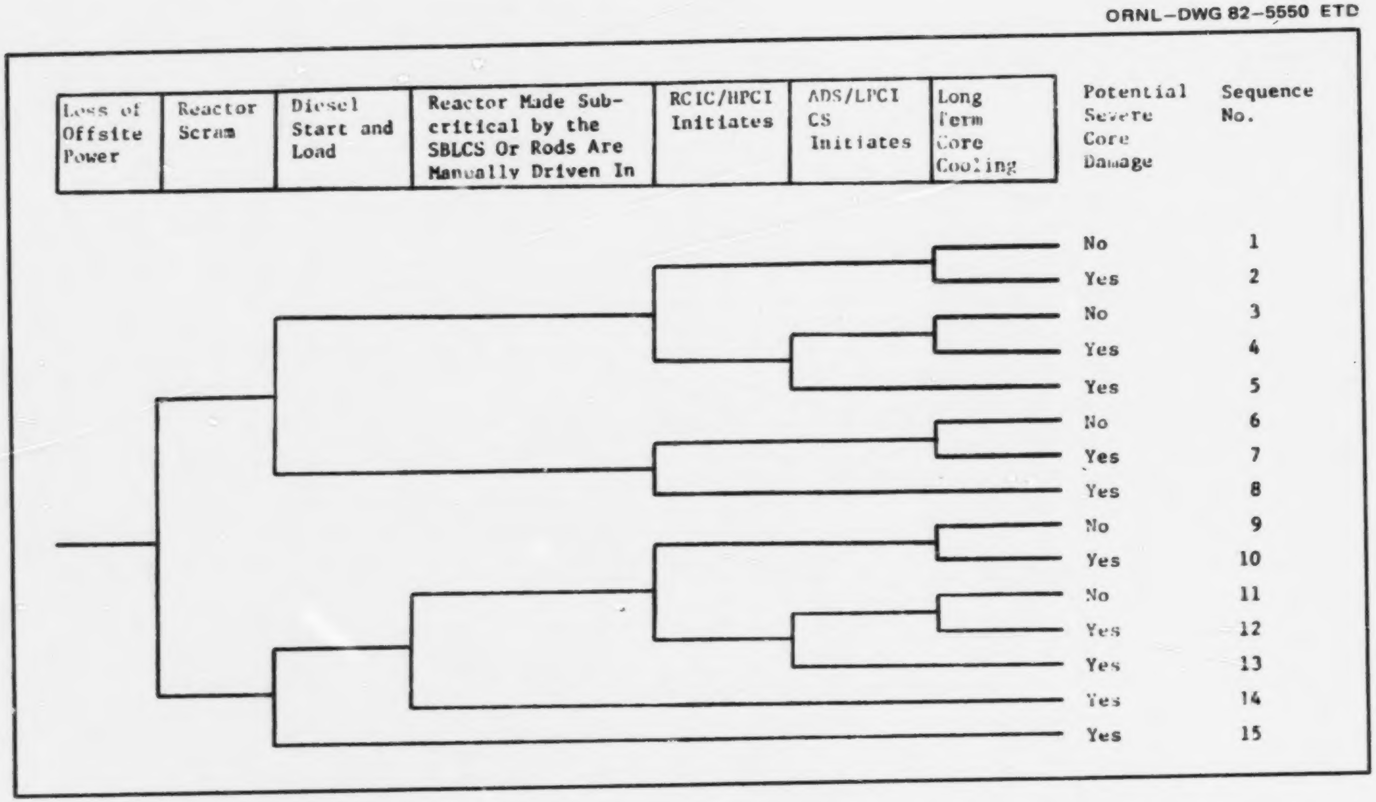

ORNL-DWG 82-5550 ETD
Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

Fig. A.7. Standard event tree for BWR loss of offsite power.

generators must energize at least one safety-related bus, in general, for success.

4. Reactor made subcritical by the SBLC system or rods are manually driven in. Success of this function requires success of the diesel generators. Both the control rod drive pumps and the standby liquid control system pumps are driven by ac motors fed from a safety-related bus. If scram fails, ac power is necessary for either of these alternate shutdown modes to be successful.

5. RCIC/HPCI initiates. Requirements for success of this function are identical to those discussed for a BWR loss of main feedwater. The RCIC/HPCI function relies only on dc power for initiation and turbine control purposes; thus, given a total loss of ac power, RCIC/HPCI will prevent core damage provided DC power and sufficient steam are available to the RCIC/HPIC turbines.

The amount of time batteries can supply reliable service is plant specific. Eight hours is a somewhat typical time for availability of a fully loaded battery; however, this time could be extended by load shedding.

Older BWRs equipped with isolation condensers and feedwater coolant injection instead of RCIC and HPCI have different requirements for success. These requirements are similar to those discussed under the BWR loss of main feedwater event tree description, with the additional requirement that ac power be available for the feedwater pumps. The makeup water to the shell side of the IC also requires success of a pump powered from a diesel-backed bus or a diesel-powered fire pump.

6. ADS/LPCI/CS initiates. Successful operation of this function is equivalent to that discussed in the BWR loss of main feedwater event tree description. At least one safety-related bus must be supplied by the diesel generators because both the core spray and LPCI pumps use ac power.

7. Long-term core cooling. Success of this function is similar to that for a loss of main feedwater flow. An additional requirement for success is the restoration of ac power before loss of the dc control power to the turbine controllers.

8. Loss-of-offsite power sequences resulting in potential severe core damage. Ten of the fifteen sequences identified are considered to result in potential severe core damage. These sequences are

- success of the ECCS (RCIC/HPCI or ADS/LPCI/CS) and failure of long-term core cooling (sequences 2, 4, 10, and 12),
- complete failure of the ECCS given success of the diesel generators (sequences 5 and 13),
- failure of long-term core cooling given failure of the diesel generators and success of the RCIC/HPCI (sequence 7),
- failure of the RCIC/HPCI given failure of the diesels (sequence 8),

[redacted]

- failure to rapidly reduce the reactor's thermal output via injection of negative reactivity given success of the diesels and a failure to scram (sequence 14),
- failure of the diesels to start and load given a failure to scram (sequence 15).

A.7 BWR Loss-of-Coolant Accident

A functional event tree was constructed to define a representative response of a BWR to a LOCA in terms of critical safety functions. The normal mitigating sequence for a LOCA depends on the break size. Small breaks of interest in this study require reactor scram and RCIC/HPCI operation. If RCIC/HPCI fails, then ADS/LPCI/CS is available. (A large LOCA requires reactor scram and operation of either LPCI or CS. Either a small or large LOCA may be accommodated by a single event tree because the low-pressure high-capacity pumps will initiate if the capacity of the high-pressure systems is inadequate.)

The event tree is shown in Fig. A.8, and the functions and sequences leading to potential severe core damage follow.

1. Initiating event (LOCA). Any breach in the reactor coolant system that results in coolant loss in excess of the capacity of the control rod drive pumps and RCIC is considered a LOCA.

2. Reactor maintained subcritical. Success of this event is defined as the rapid insertion of sufficient control rods to place the core in a subcritical condition.

3. HPCI/RCIC adequate. Success for this function requires the initiation and operation of HPCI/RCIC. The capacity provided must be adequate to replace the coolant being continually lost through the RCS break.

4. ADS/LPCI/CS response adequate. Success of this function is dependent on the reason for its initiation: a small LOCA and failure of the RCIC/HPCI or a large LOCA. A large LOCA is defined as a break in the RCS that is sufficient to reduce the system pressure, through blowdown, to the operating range of the LPCI/CS systems. All other LOCAs are considered small. Successful operation of ADS/LPCI/CS systems under small LOCA conditions is identical to that discussed for a BWR loss of main feedwater.

5. Long-term core cooling. Success of this state requires that heat rejection to the environment commence within 2 to 27 h, depending on the size of the break. Long-term core cooling may be initiated when the reactor has depressurized below the RCIC/HPCI operating pressure. Functional success is difficult to specify in terms of specific component operability for the same reasons discussed under long-term core cooling following a loss of main feedwater.

ORNL-DWG 82-5551 ETD

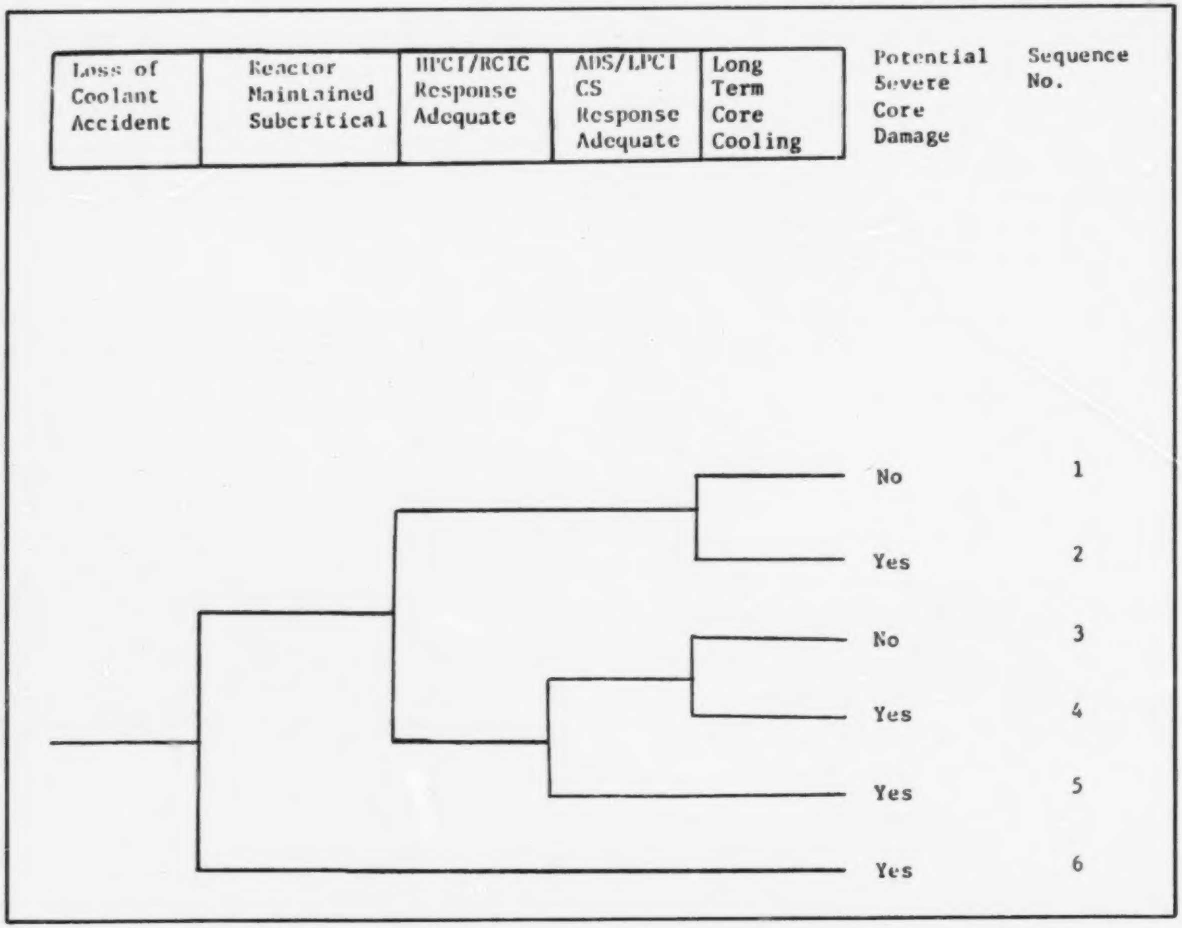

Loss of Coolant Accident
Reactor Maintained Subcritical
HPCI/RCIC Response Adequate
ADS/LPCI CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
No
1
Yes
2
No
3
Yes
4
Yes
5
Yes
6

Fig. A.8. Standard event tree for BWR loss-of-coolant accident.

[redacted]

6. Loss-of-coolant-accident sequences resulting in potential severe core damage. Four of six sequences identified are considered to result in potential severe core damage. These sequences are

- failure of long-term core cooling given success of the RCIC/HPCI (sequence 2),
- failure of long-term core cooling given success of ADS/LPCI/CS (sequence 4),
- complete failure of ECCS (sequence 5),
- failure to scram the reactor (sequence 6).

A.8 BWR Main Steam Line Break

An event tree was constructed to define a representative functional response of a BWR to a main steam line break. The event tree shown in Fig. A.9 illustrates the normal mitigating sequence and alternative sequences. The normal sequence consists of reactor vessel isolation, reactor scram, and operation of RCIC. Two alternate methods exist, depending on the size and location of the break. The first is reactor vessel isolation, reactor scram, and either (1) HPCI or (2) ADS and LPCI or CS. The second is reactor scram and either LPCI or CS operation. The event tree functions and the sequences leading to potential severe core damage follow.

1. Initiating event (main steam line break). The initiating event is a break in a main steam line.

2. Reactor vessel isolated. Success for this function is dependent on break location. If the reactor vessel can be isolated, then the cooldown and depressurization rate can be controlled. Failure to isolate the reactor vessel from the break will result in blowdown through the broken steam line. If the break occurs upstream of the inboard MSIV, the vessel cannot be isolated. If the break occurs between the MSIVs, then closure of the inboard MSIV will isolate the vessel. A break downstream of both MSIVs requires closure of either valve for success.

3. Reactor scram. Success for reactor scram with the vessel isolated is identical to that for a loss of main feedwater. Success requirements for an unisolated reactor vessel are similar to those for a LOCA.

4. RCIC/HPCI response adequate. Success for this function requires an isolated reactor vessel or a break sufficiently small to allow for RCIC or HPCI functionability. Beyond this, requirements for success are similar to those of loss of main feedwater.

5. ADS/LPCI/CS response adequate. Success of ADS/LPCI/CS given reactor vessel isolation success is similar to that of a BWR loss of main feedwater. Success of ADS/LPCI/CS given failure of reactor vessel isolation is similar to that of a LOCA.

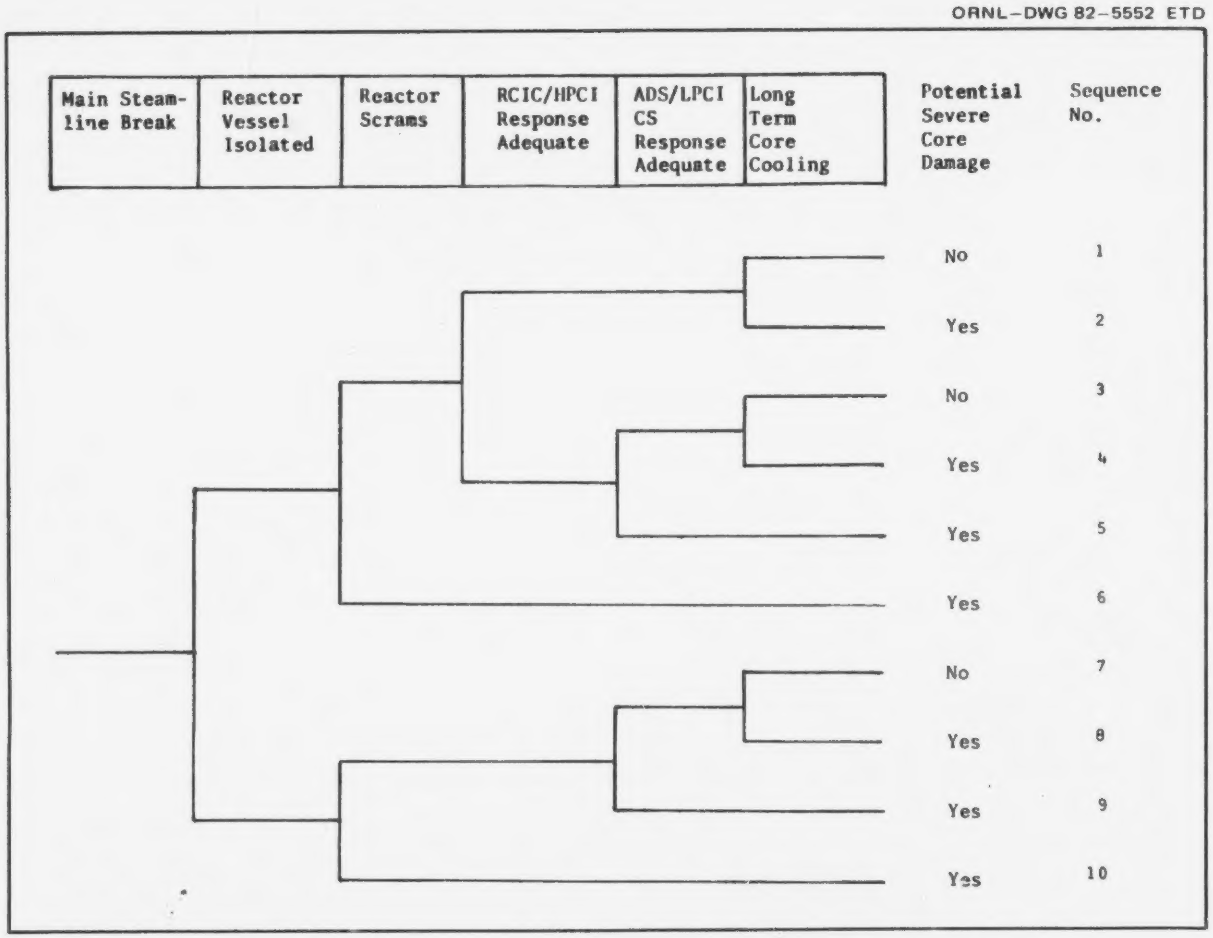

ORNL-DWG 82-5552 ETD
Main Steam-line Break
Reactor Vessel Isolated
Reactor Scrams
RCIC/HPCI Response Adequate
ADS/LPCI CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
No
1
Yes
2
No
3
Yes
4
Yes
5
Yes
6
No
7
Yes
8
Yes
9
Yes
10

Fig. A.9. Standard event tree for BWR main steam line break.

[redacted]

6. Long-term core cooling. Success of long-term core cooling given success of reactor vessel isolation is similar to that for a BWR loss of main feedwater. If the vessel is not successfully isolated, then success requirements are similar to those for a LOCA.

7. Main steam line break sequences leading to potential severe core damage. Seven of ten sequences are considered to lead to potential severe core damage. These sequences are

- failure of long-term core cooling given success of RCIC/HPCI or ADS/LPCI/CS (sequences 2, 4, and 8);
- complete failure of the ECCS with or without reactor isolation (sequences 5 and 9);
- failure of the reactor to scram (sequences 6 and 10).

Appendix B

PRECURSOR SUMMARY SHEETS
AND EVENT TREES

Note

This appendix is bound separately as Volume 2 of this document.

Appendix C

SUPPORT MATERIAL FOR SELECTION OF POTENTIAL PRECURSORS THAT ARE CONSIDERED SIGNIFICANT

[redacted]

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Initiating Event Frequency and Function Failure Probability Estimates C-5

BWR High-Pressure Coolant Injection System Failures C-14

Precursor Probability Measure Calculations C-38

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Table C.1. Initiating event frequency and function fai

Initiating event/function under consideration	Event description NSIC accession number	Event date	Plant	Plant age (d)	Description	Severity	Total numb of events × severit
						PWR loss of main feedwater	
Initiating event	Initiating event frequency for a PWR LOFW was determined based on a review of main-feedwater-related events reported in NUREG-0611 (pp. II-15 through II-27). Eighty LOFW initiating events occurred over a three-calendar-year period. Approximately 50% appeared to be rectifiable in the short term. Westinghouse LOFW events were used for this estimate because the majority of PWR operating hours are contributed by Westinghouse plants.						40
Reactor trip failure	Demand failure probability for failure to trip was assumed to be equal to value calculated in WASH-1400 (p. II-97).						
AFW and secondary heat removal failure given trip success	81523	June 18, 1973	Turkey Point 4	7	Failure of pumps to auto-start due to failure to install fuses	0.1	6.1
	90421	Apr. 7, 1974	Point Beach 1	1252	Failure to deliver flow due to clogged suction stainers	1.0	
	91676	May 8, 1974	Turkey Point 3	565	Failure of pumps to start due to overtightened packings and controller malfunction	1.0	
	108078	Nov. 5, 1975	Kewaunee	608	Failure to deliver flow due to clogged suction strainers	1.0	
	133706	Dec. 11, 1977	Davis-Besse 1	121	Loss of AFW pump control due to mechanical binding and blown control power fuses	1.0	
	137305	Mar. 25, 1978	Farley	228	Failure of turbine-driven pumps to start plus open bypass valves	0.5	
	138830	Mar. 20, 1978	Rancho Seco	1281	Failure of AFW to deliver flow due to NNI failure	1.0	
	153164	Mar. 28, 1979	TMI-2	365	Failure of AFW to deliver flow due to closed valves	0.5	
AFW and secondary heat removal failure given failure to trip	Demand failure probability for failure of AFW and secondary heat removal given failure to trip assumed to be 10 times failure probability calculated for AFW and secondary heat removal given trip.						
PORV not demanded	Probability that the PORV would not be demanded following a reactor trip with successful AFW initiation was assumed to be 0.9.						
Failure of open PORV to close and failure of operator to detect failure and close isolation valve	Probability that the PORV would stick open once it was open was assumed equal to 0.01/D. Probability of the operator failing to isolate the open valve was based on precursor information: 7 events involving a failed-open PORV with 2 of these events involving a failure to isolate the valve. (These events are detailed in the discussion of small LOCA initiating events herein.) This results in a combined failure probability of 0.0029.						
Failure of HPI given failure of PORV or PORV isolation valve to close	78418	Feb. 2, 1973	Maine Yankee	102	Failure of charging pump valves to open due to ice accumulation	1.0	2.0
	125106	May 6, 1977	Salem 1	146	Failure to clear pumps from overpressure protection during plant heatup (potential failure on demand)	1.0	

C.1. Initiating event frequency and function failure probability estimates

Description	Severity	Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions	Initiating event frequency estimate (per year)	Demand failure probability estimate (per demand)		Value used in ASP calculations
						Minimum function	Maximum function	
PWR loss of main feedwater								
n a review of main-feedwater-related LOFW initiating events occurred over rectifiable in the short term. majority of PWR operating hours are		40		72 post-1968 plant operating years	5.6×10^{-1}			5.6×10^{-1}/ year
equal to value calculated in WASH-1400								3.6×10^{-5}/D
re of pumps to auto-start o failure to install	0.1	6.1	6.1	12 per plant year due to testing plus 1 per shutdown of <48 h plus 2 per shutdown >48 h. Based on 1979 operational data from NUREG/CR-1496, an average of 7.9 outages of <48 h and 3.7 outages of >48 h occurred per plant. This results in 5624 expected demands.		1.1×10^{-3}	1.1×10^{-3}	1.1×10^{-3}/D
re to deliver flow due to ed suction stainers	1.0							
re of pumps to start due ertightened packings and oller malfunction	1.0							
re to deliver flow due to ed suction strainers	1.0							
of AFW pump control due to nical binding and blown ol power fuses	1.0							
re of turbine-driven pumps art plus open bypass	0.5							
re of AFW to deliver flow o NNI failure	1.0							
re of AFW to deliver flow o closed valves	0.5							
removal given failure to trip assecondary heat removal given trip.								1.1×10^{-2}/D
tor trip with successful AFW								0.9/D
assumed equal to 0.01/D. Probabilon precursor information: 7 events failure to isolate the valve. (These vents herein.) This results in a								2.9×10^{-3}/D
re of charging pump s to open due to ice ulation	1.0	2.0	5.0	12 per plant year due to testing, which result in 2472 total demands.		8.1×10^{-4}	2.0×10^{-3}	1.3×10^{-3}/D
re to clear pumps from ressure protection during heatup (potential fail- demand)	1.0							

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Table C.1 (continued)

Initiating event/function under consideration	Event description						Total number of events × severity	Total number o events and potential events × severity
	NSIC accession number	Event date	Plant	Plant age (d)	Description	Severity		
	135079	Nov. 23, 1977	Robinson 2	2621	Failure to clear pumps from overpressure protection during plant heatup (potential failure on demand)	1.0		
	153164	Mar. 28, 1979	TMI-2	365	HPI flow incorrectly reduced when required	1.0		
	154286	Nov. 28, 1979	Salem 1	1082	Inoperable SI pumps due to loose impeller locknuts (potential failure on demand)	1.0		
Failure of HPI given failure of AFW and secondary heat removal	Probability value used for failure of the HPI function to provide core cooling given failure of AFW and secondary heat removal was dependent on date at which precursor event occurred and on type of HPI function provided at the plant. For events occurring before Mar. 28, 1979, the probability of failure was assumed to be 1.0. For events occurring after Mar. 28, 1979, a value of 0.1 was assumed for plants with HPI pumps capable of providing flow at the relief valve set point and a value of 0.5 was assumed for plants that required manual depressurization to achieve injection flow.							
Failure of long-term core cooling	59484	Jan. 12, 1971	Point Beach 1	71	Sump isolation valves failed shut (potential failure on demand)	1.0	2.0	8.0
	65757	Apr. 16, 1971	Point Beach 1	165	Sump isolation valves failed shut (potential failure on demand)	1.0		
	109295	Dec. 19, 1975	Oconee 1	974	Frozen BWST level transmitter impulse lines (potential failure on demand)	1.0		
	120995	Nov. 11, 1976	Rancho Seco	784	Sump isolation valves failed shut	1.0		
	130889	Oct. 11, 1977	Surry 2	1928	Failure to close recirculation service water system drain valves (potential failure on demand)	1.0		
	141523	Oct. 17, 1978	Calvert Cliffs 2	686	LPSI pumps airbound (potential failure on demand)	1.0		
	143296	Oct. 20, 1977	Maine Yankee	1823	Inadvertent closure of RWST outlet valves	1.0		
	153003	Oct. 24, 1979	Oconee 2	2173	Failure to reposition LPR service water valves after testing (potential failure on demand)	1.0		
					PWR loss of offsite power			
Initiating event	61565	Sept. 2, 1971	Palisades	101	LOOP due to tripped line plus failed relay	0.5[a]	9.8	
	65757	Feb. 5, 1971	Point Beach 1	95	LOOP due to breaker opening (reason unspecified)	0.5[a]		
	71694	May 17, 1972	Palisades	359	LOOP due to spurious relay operation	0.5[a]		
	82198	July 4, 1973	Turkey Point 3	257	LOOP due to failure to transfer on reactor trip due to unconnected wire	0.1		

Table C.1 (continued)

						Demand failure probability estimate (per demand)		
tion	Severity	Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions	Initiating event frequency estimate (per year)	Minimum function	Maximum function	Value used in ASP calculations
pumps from tection during tential fail-	1.0							
ctly reduced	1.0							
mps due to ocknuts (po- on demand)	1.0							
ing given failure of AFW ccurred and on type of 979, the probability of value of 0.1 was assumed point and a value of 0.5 ection flow.								See event description section
alves failed failure on	1.0	2.0	8.0	12 per reactor year due to testing plus 1 per shutdown down >48 h (3.7 such outages per reactor year, see AFW failure demand estimate). This results in 3234 total demands.		6.2×10^{-4}	2.5×10^{-3}	1.2×10^{-3}/D
alves failed failure on	1.0							
l transmitter otential fail-	1.0							
alves failed	1.0							
recirculation ystem drain l failure on	1.0							
und (potential d)	1.0							
ure of RWST	1.0							
ition LPR ser- s after test- ailure on	1.0							
PWR loss of offsite power								
pped line plus	0.5^a	9.8		206 post-1968 operating years	4.8×10^{-2}			4.1×10^{-2}/ year
ker opening fied)	0.5^a							
rious relay	0.5^a							
lure to trans- rip due to	0.1							

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Table C.1 (continued)

Initiating event/function under consideration	Event description						Total number of events × severity	Total number of events and potential events × severity
	NSIC accession number	Event date	Plant	Plant age (d)	Description	Severity		
	85370	Oct. 21, 1973	Ginna	1443	LOOP due to line trip plus power swings due to high generated power	0.5[a]		
	93702	Apr. 25, 1974	Turkey Point 4	318	LOOP due to sneak circuit and isolated startup transfer	0.5[a]		
	97578	Oct. 17, 1974	Palisades	1242	LOOP due to spurious relay operation	0.5[a]		
	117944	Aug. 10, 1976	Millstone 2	298	LOOP due to salt spray contamination during hurricane	0.5[a]		
	125563	May 16, 1977	St. Lucie 1	389	LOOP due to grid disturbances	0.5[a]		
	128935	Aug. 22, 1977	Ft. Calhoun	1477	LOOP due to defective relay reset mechanism	0.5[a]		
	130111	Sept. 1, 1977	Cook 1	957	LOOP due to multiple lightning strikes	0.1		
	130119	Sept. 24, 1977	Palisades	2315	LOOP during electrical storm	0.5[a]		
	132927	Nov. 29, 1977	Davis-Besse 1	109	LOOP due to premature manual transfer	0.1		
	132943	Nov. 25, 1977	Palisades	2377	LOOP due to R bus deenergization (reason undetermined)	0.5[a]		
	132958	Dec. 11, 1977	Palisades	2393	LOOP due to R bus deenergization (reason unspecified)	0.5[a]		
	135006	Sept. 16, 1977	Farley	38	LOOP due to relay operation during lightning strike	0.5[a]		
	137543	Apr. 13, 1978	Calvert Cliffs 1	1284	LOOP due to switch-yard protective relaying (reason unspecified)	0.5[a]		
	139565	May 14, 1978	St. Lucie 1	752	LOOP due to improper switching at one substation and improper connections at another	0.5[a]		
	140335	July 28, 1978	Beaver Valley 1	809	LOOP due to main transformer fault plus improper relay operation	0.5[a]		
	143219	July 13, 1977	Indian Point 3	463	LOOP due to severe electrical storms	0.5[a]		
	152187	Sept. 3, 1979	St. Lucie 1	1229	LOOP due to switchyard failure	0.5[a]		
	152951	Oct. 15, 1979	Davis-Besse 1	794	LOOP due to output breaker failure	0.5[a]		
Failure of turbine generator to run back and assume house loads	The probability value used for failure to runback was based on the availability of the function at a particular plant. For plants without the runback feature, the value was assumed to be 1.0. For plants with a runback feature, the value was assumed to be 0.75.							
Failure of emergency power	63144	Mar. 8, 1971	Robinson 2	169	DGs failed to run due to improper instrument line rerouting	1.0	3.5	5.5

Table C.1 (continued)

cription			Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions	Initiating event frequency estimate (per year)	Demand failure probability estimate (per demand)		Value used in ASP calculations
lant age (d)	Description	Severity					Minimum function	Maximum function	
1443	LOOP due to line trip plus power swings due to high generated power	0.5^a							
318	LOOP due to sneak circuit and isolated startup transfer	0.5^a							
1242	LOOP due to spurious relay operation	0.5^a							
298	LOOP due to salt spray contamination during hurricane	0.5^a							
389	LOOP due to grid disturbances	0.5^a							
1477	LOOP due to defective relay reset mechanism	0.5^a							
957	LOOP due to multiple lightning strikes	0.1							
2315	LOOP during electrical storm	0.5^a							
109	LOOP due to premature manual transfer	0.1							
2377	LOOP due to R bus deenergization (reason undetermined)	0.5^a							
2393	LOOP due to R bus deenergization (reason unspecified)	0.5^a							
38	LOOP due to relay operation during lightning strike	0.5^a							
1284	LOOP due to switch-yard protective relaying (reason unspecified)	0.5^a							
752	LOOP due to improper switching at one substation and improper connections at another	0.5^a							
809	LOOP due to main transformer fault plus improper relay operation	0.5^a							
463	LOOP due to severe electrical storms	0.5^a							
1229	LOOP due to switchyard failure	0.5^a							
794	LOOP due to output breaker failure	0.5^a							See event description section
169	DGs failed to run due to improper instrument line rerouting	1.0	3.5	5.5	12 per reactor year due to testing plus 0.1 LOOP demand per year, which result in 2492 total demands.		1.4×10^{-3}	2.2×10^{-3}	1.8×10^{-3}/D

was based on the availability of the function at
k feature, the value was assumed to be 1.0. For
ed to be 0.75.

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Table C.1

Initiating event/function	Event description					
	NSIC accession number	Event date	Plant	Plant age (d)	Description	Severi
	103207	May 25, 1975	Turkey Point 4	713	DGs failed to load due to breaker and relay failures	1.0
	116212	July 20, 1976	Millstone 2	277	Failure of safety-related buses to load due to incorrect undervoltage set points	0.5
	132942	Dec. 9, 1977	Prairie Island 1	1469	DGs inoperable due to improper shutdown procedure (potential demand failure)	0.5
	132979	May 15, 1977	Millstone 2	576	DG fuel supply valves discovered shut (potential demand failure)	1.0
	150882	June 6, 1979	Crystal River	873	DGs trip during testing due to reactive load imbalance	1.0
	152835	July 31, 1979	Calvert Cliffs 1	1758	Undervoltage protection circuitry found tripped (potential demand failure)	0.5
Failure of AFW following emergency power success	See loss-of-main-feedwater entry.					
Failure of AFW and secondary heat removal given failure of emergency power	Probability value assumed for this function was based on the design of the AFW system in the plant in which the precusor events occurred. For units with only electrically operated pumps or with re quirements for service water for turbine-driven pump cooling, the failure probability was assumed be 1.0. For units with self-cooled turbine-driven pumps but with electrically operated valves capable of manual operation, the failure probability was assumed to be 0.1. This value was based on sufficie time being available for manual initiation of AFW following LOFW or LOOP and operating procedures that are assumed to be sufficiently specific to allow for manual initiation within the available t period. For units with self-cooled turbine-driven pumps and with valves without ac power (except vital power) dependancy, the failure probability was assumed to be 0.02. This number was based on the fact that, with few exceptions, all AFW systems having turbine-driven pumps use only one such pump and that, based on a review of LERs related to pump failures, 0.02/demand appears to be a representative failure-on-demand number for turbine-driven pumps.					
PORV demanded	See loss-of-main-feedwater entry.					
PORV or PORV isolation valve closure	See loss-of-main-feedwater entry.					
Failure of HPI	See loss-of-main-feedwater entry.					
Failure of long-term core cooling	See loss-of-main-feedwater entry.					
					PWR small loss-o	
Initiating event	65969	Sept. 8, 1971	Palisades	107	Open PORV due to unclear wiring diagrams during testing at hot shutdown	0.1
	103077	May 1, 1975	Robinson 2	1684	RCP seal failure	1

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Table C.1 (continued)

on		Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions	Initiating event frequency estimate (per year)	Demand failure probability estimate (per demand)		Value used in ASP calculations
Description	Severity					Minimum function	Maximum function	
DGs failed to load due to breaker and relay failures	1.0							
Failure of safety-related buses to load due to incorrect undervoltage set points	0.5							
DGs inoperable due to improper shutdown procedure (potential demand failure)	0.5							
DG fuel supply valves discovered shut (potential demand failure)	1.0							
DGs trip during testing due to reactive load imbalance	1.0							
Undervoltage protection circuitry found tripped (potential demand failure)	0.5							
the design of the AFW system in the plants nly electrically operated pumps or with re- ling, the failure probability was assumed to								See event description section
electrically operated valves capable of be 0.1. This value was based on sufficient ing LOFW or LOOP and operating procedures r manual initiation within the available time								
valves without ac power (except vital o be 0.02. This number was based on the urbine-driven pumps use only one such pump ures, 0.02/demand appears to be a represen- .								
PWR small loss-of-coolant accident								
Open PORV due to unclear wiring diagrams during testing at hot shutdown	0.1	1.7	1.7	206 post-1968 reactor years	8.3×10^{-3}			8.3×10^{-3}/year
RCP seal failure	1							

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Table C.1 (continued)

Initiating event/function underconsideration	Event description						Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions
	NSIC accession number	Event date	Plant	Plant age (d)	Description	Severity			
	141097	Mar. 29, 1978	TMI-2	1	Open PORV due to inverter failure	0.5			
	145209	Dec. 20, 1978	Fort Calhoun 1	1962	Open PORVs due to technician pulling recorder fuses during trouble shooting	0.1			
Failure of reactor trip	See loss-of-main-feedwater entry.								
Failure of AFW and secondary heat removal	See loss-of-main-feedwater entry.								
Failure of HPI	See loss-of-main-feedwater entry.								
Low-pressure recirculation and LPI/HPI cross-connect	Probability value used for this function was assumed to be the same as that calculated for PWR long-term core cooling following use of HPI, as detailed under loss-of-main-feedwater entry.								
					PWR main steam line break				
Initiating event	Value used for this initiating event frequency was assumed to be equal to the large LOCA value used in the *Reactor Safety Study* (WASH-1400, main report, p. 157).								
Failure of reactor trip	See loss-of-main-feedwater entry.								
Failure of steam generator isolation	122366	Jan. 10, 1977	Arkansas 1	888	Frozen SLBIC sensing lines (potential failure on demand)	0.5	2.6	3.1	12 per reactor year due to testing, which result in 2472 post-1968 demands.
	124920	Apr. 16, 1977	Crystal River 3	92	Incomplete startup valve closure due to out-of-calibration pressure transmitter	0.5			
	147223	Jan. 6, 1979	Crystal River 3	722	Failure of feedwater block isolation valve	0.1			
	147400	Feb. 19, 1979	Point Beach 2	3031	Failure of MSIVs to close due to deposits on valve stem or packing hardening	1.0			
	149250	Apr. 14, 1979	Trojan	1216	Failure of MSIVs to close due to stem/packing binding	1.0			
Failure of AFW and secondary removal	See loss-of-main-feedwater entry.								
Failure of HPI	In addition to the previously identified HPI-related events, the following events are applicable to the use of this function during steam line break mitigation:								
	89153	Feb. 21, 1974	Prairie Island 1	82	RWST isolation valves found in open position due to test and valve logic inconsistencies (potential failure on demand)	1.0			
	97107	Oct. 22, 1974	Zion 2	302	Failure to inject BIT contents due to A train power supply failure and B train valve failure	1.0			
	120207	Oct. 28, 1976	Trojan	318	Failure of charging pump suction valves to open	1.0			

Table C.1 (continued)

Description	Severity	Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions	Initiating event frequency estimate (per year)	Demand failure probability estimate (per demand)		Value used in ASP calculations
						Minimum function	Maximum function	
Open PORV due to inverter failure	0.5							
Open PORVs due to technician pulling recorder fuses during trouble shooting	0.1							
the same as that calculated for PWR nder loss-of-main-feedwater entry.								1.2×10^{-3}/D
PWR main steam line break								
to be equal to the large LOCA value . 157).								10^{-4}/year
Frozen SLBIC sensing lines (potential failure on demand)	0.5	2.6	3.1	12 per reactor year due to testing, which result in 2472 post-1968 demands.		1.1×10^{-3}	1.3×10^{-3}	1.2×10^{-3}/D
Incomplete startup valve closure due to out-of-calibration pressure transmitter	0.5							
Failure of feedwater block isolation valve	0.1							
Failure of MSIVs to close due to deposits on valve stem or packing hardening	1.0							
Failure of MSIVs to close due to stem/packing binding	1.0							
, the following events are applicable to :								
RWST isolation valves found in open position due to test and valve logic inconsistencies (potential failure on demand)	1.0							
Failure to inject BIT contents due to A train power supply failure and B train valve failure	1.0							
Failure of charging pump suction valves to open	1.0							

Table C.1 (continued)

Initiating event/function under consideration	Event description						Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions
	NSIC accession number	Event date	Plant	Plant age (d)	Description	Severity			
	135077	Oct. 26, 1977	Robinson 2	2593	BIT thermowell coupling failure	1.0			
	142349	Nov. 29, 1978	Indian Point 2	2014	BIT discharge line plug due to boric acid solidification (potential failure on demand)	1.0			
	These events, combined with those previously identified, result in these estimates:						5.0	10.0	12 per plant year d testing, which resu 2472 total demands.
PORV opened due to continued HPI following a steam line break	Value of this demand probability was assumed to be 0.8.								
PORV or PORV isolation valve failure to close following continued HPI after a steam line break	Value for this demand probability was assumed to be equal to a combined failure probability for the PORV isolation valve ($\sim 10^{-3}/D$) and for an operation error in failing to close the valve ($\sim 5 \times 10^{-3}/D$). This results in a failure probability estimate of $6 \times 10^{-3}/D$.								
Failure of long-term core cooling	See loss-of-main-feedwater entry.								
	BWR loss of main feedwater								
Initiating event	Eighty-one loss-of-feedwater events were reported in NUREG-0626 to have occurred in a 3-year 66-plant-year period in BWRs critical after 1968. In 42 of these events, feedwater was successfully restored, which results in a rectification probability estimate of ~50%.						39		
Reactor subcritical	Success of this function requires either that the reactor be scrammed or the operator must drive in the control rods or initiate SBLC. The value assumed for scram failure (obtain from WASH-1400) is $1.3 \times 10^{-5}/D$, (App. II, p. 358). A failure to scram is considered a highly stressful situation; thus, the conditional probability that the operator will fail to shut down the reactor manually given a failure to scram was assumed to be 0.1. This results in a total failure probability of $1.3 \times 10^{-6}/D$.								
Failure of RCIC and HPCI	85738	Nov. 19, 1973	Browns Ferry 1	65	RCIC and HPCI failed during testing	0.1	4.9		12 per plant year testing plus 0.58 demands per plant plus 10 LOOPs, whi sult in 1253 total mands.
	95040	Aug. 23, 1974	Browns Ferry 2	33	The HPCI injection valve fails to open with RCIC inoperable	1.0			
	101444	Mar. 22, 1975	Browns Ferry 1	528	Cable tray fire causes extensive damage	1.0			
	106333	Sept. 9, 1975	Quad Cities	904	HPCI was found inoperable during test	1.0			
	128906	Aug. 8, 1977	Cooper	1287	A loss of the no-break power supply caused RCIC and HPCI to be inoperable	0.5			
	149961	June 3, 1979	Hatch 1	334	HPCI failed to start with RCIC inoperable during a plant transient	1.0			
	150499	June 28, 1979	Hatch 2	359	RCIC and HPCI isolate following plant scram	0.1			
	150742	June 22, 1979	Peach Bottom 3	278	Lightning causes fuse in bus serving HPCI and RCIC auto-initiation to fail	0.1			

Table C.1 (continued)

scription			Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions	Initiating event frequency estimate (per year)	Demand failure probability estimate (per demand)		Value used in ASP calculations
Plant age (d)	Description	Severity					Minimum function	Maximum function	
2593	BIT thermowell coupling failure	1.0							
2014	BIT discharge line plug due to boric acid solidification (potential failure on demand)	1.0							
	tified, result in these estimates:		5.0	10.0	12 per plant year due to testing, which result in 2472 total demands.		2.0×10^{-3}	4.0×10^{-3}	2.8×10^{-3}/D
	be 0.8.								8.0×10^{-1}/D
	be equal to a combined failure probability for the ion error in failing to close the valve (~5 x 10^{-3}/ ate of 6 x 10^{-3}/D.								6 x 10^{-3}/D
	BWR loss of main feedwater								
	d in NUREG-0626 to have occurred in a 3-year 66-plant- of these events, feedwater was successfully restored, imate of ~50%.		39			5.8×10^{-1}			5.8×10^{-1}/ year
	e reactor be scrammed or the operator must drive in the d for scram failure (obtain from WASH-1400) is cram is considered a highly stressful situation; thus, ll fail to shut down the reactor manually given a sults in a total failure probability of 1.3 x 10^{-6}/D.								1.3×10^{-6}/D
65	RCIC and HPCI failed during testing	0.1	4.9		12 per plant year due to testing plus 0.58 LOFW demands per plant year plus 10 LOOPs, which result in 1253 total demands.		3.9×10^{-3}	3.9×10^{-3}	3.9×10^{-3}/D
33	The HPCI injection valve fails to open with RCIC inoperable	1.0							
528	Cable tray fire causes extensive damage	1.0							
904	HPCI was found inoperable during test	1.0							
1287	A loss of the no-break power supply caused RCIC and HPCI to be inoperable	0.5							
334	HPCI failed to start with RCIC inoperable during a plant transient	1.0							
359	RCIC and HPCI isolate following plant scram	0.1							
278	Lightning causes fuse in bus serving HPCI and RCIC auto-initiation to fail	0.1							

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Table C.1 (continued)

Initiating event/function under consideration	Event description						Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions
	NSIC accession number	Event date	Plant	Plant age (d)	Description	Severity			
	153810	Nov. 20, 1979	Brunswick 1	1139	RCIC tripped during a plant transient with HPCI unavailable	0.1			
Failure of ADS	115870	July 6, 1976	Vermont Yankee	1565	Improper insulation caused several ADS valves to fail	1.0	4.0	4.0	1 per plant year due to testing, which results in 148 total demands.
	120439	Nov. 1, 1976	Quad Cities 1	1841	Two ADS valves failed to open during testing	1.0			
	120443	Nov. 1, 1979	Quad Cities 2	1650	Two ADS valves failed to open during testing	1.0			
	124222	Apr. 8, 1977	Duane Arnold	1110	Six main steam relief valves failed to lift during testing	1.0			
Failure of LPCI or CS	No simultaneous failures of LPCI and CS were observed during the 148 post-1968 BWR plant years. Assuming a simultaneous failure of both LPCI and CS occurs during the next demand results in a demand failure probability estimate of $1/(148 \times 12$ test/year $+ 1)$ demands $= 5.6 \times 10^{-4}$/D.								
Failure of long-term core cooling	The value assumed was 1.1×10^{-4}/D. This is equivalent to the estimate used in WASH-1400 for the high-pressure service water system (App. II, p. 419), which provides cooling water to the RHR service water heat exchanger, is the principle means of rejecting heat to the environment in the RHR system, and is the dominant failure contributor.								
BWR loss of offsite power									
Initiating event	79565	Jan. 12, 1972	Vermont Yankee	252	Loss of normal station power	0.5^a	4.7		148 post-1968 operating years
	83833	Sept. 8, 1973	Oyster Creek	1589	Loss of offsite power	0.5^a			
	85566	Nov. 19, 1973	Browns Ferry 1	65	Loss of ac power causes HPCI/RCIC to fail	0.5^a			
	86990	Nov. 17, 1973	Nine Mile Point	1886	Incoming power lost due to a worker bumping a relay	0.1			
	102146	Apr. 9, 1975	Brunswick 2	6	Loss of offsite power	0.1			
	106616	Sept. 13, 1975	Pilgrim	1184	Loss of offsite power	0.5^a			
	116780	Aug. 10, 1976	Millstone 1	1959	Loss of offsite power during Hurricane Belle	0.5^a			
	135932	Feb. 6, 1978	Pilgrim 1	2061	All offsite power lines lost	0.5^a			
	140140	Aug. 6, 1978	Pilgrim 1	2242	Lightning causes 100% load rejection	0.5^a			
	150943	July 27, 1979	Pilgrim 1	2597	Lightning strikes offsite line causing a complete loss of offsite power	0.5^a			
	151635	Aug. 18, 1979	Pilgrim 1	2629	Lightning causes a loss of offsite power	0.5^a			
Failure of reactor scram	The value assumed was 1.3×10^{-5}/D. This is the WASH-1400 estimate for failure of the RPS (App. II, p. 358).								

Table C.1 (continued)

tion	Severity	Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions	Initiating event frequency estimate (per year)	Demand failure probability estimate (per demand)		Value used in ASP calculations
						Minimum function	Maximum function	
ing a plant CI unavailable	0.1							
ion caused s to fail	1.0	4.0	4.0	1 per plant year due to testing, which results in 148 total demands.		2.7×10^{-2}	2.7×10^{-2}	2.7×10^{-2}/D
iled to open	1.0							
iled to open	1.0							
lief valves uring testing	1.0							
968 BWR plant years. As- and results in a demand 10^{-4}/D.								5.6×10^{-4}/D
d in WASH-1400 for the water to the RHR ser- environment in the RHR								1.1×10^{-4}/D
BWR loss of offsite power								
tation power	0.5[a]	4.7		148 post-1968 operating years	3.0×10^{-2}			4.1×10^{-2}/ year[b]
power	0.5[a]							
causes l	0.5[a]							
ost due to a relay	0.1							
power	0.1							
power	0.5[a]							
power during	0.5[a]							
r lines lost	0.5[a]							
100% load	0.5[a]							
s offsite line te loss of	0.5[a]							
a loss of	0.5[a]							
lure of the RPS								1.3×10^{-5}/D

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Table C.1 (continued)

Initiating event/function under consideration	Event description						Total number of events × severity	Total number of events and potential events × severity	Obser peri dem assum
	NSIC accession number	Event date	Plant	Plant age (d)	Description	Severity			
Failure of emergency power	93553	Dec. 8, 1974	Hatch 1	87	Two DGs malfunction during testing	1.0	8.0	10.0	12 per plan testing plu which resul total deman
	108869	Dec. 20, 1975	Hatch 1	464	Two DGs fail to start during testing	1.0			
	121533	Jan. 4, 1977	Brunswick 1	87	Two DGs trip during surveillance testing	1.0			
	124201	Mar. 22, 1977	Dresden 3	2273	DG fields failed to flash	1.0			
	131225	Aug. 28, 1977	Peach Bottom 2	1443	Two DGs fail to start during testing	1.0			
	132115	Nov. 29, 1977	Dresden 3	2493	DGs trip during testing	1.0			
	132947	Dec. 2, 1977	Dresden 2	2890	DGs fail to start (potential demand failure)	1.0			
	133004	June 13, 1977	Peach Bottom 2	1041	Three of four DGs rendered inoperable due to improper maintenance (potential demand failure)	1.0			
	144187	Dec. 10, 1977	Millstone 1	2616	DG and gas-turbine generator failed during testing	1.0			
	150051	June 12, 1979	Dresden 2	3473	Failure of 2 DGs during testing	1.0			
Failure to make reactor subcritical by means other than scram	Operator error is assumed to be the dominant contributor to this failure probability. Failure to initiate the SBLC system is assumed to be equivalent to failure to initiate AFW manually as reported in NUREG/CR-1278 (pp. 22-14 through 22-19). This value is taken as 5 x 10^{-3}/D.								
Failure of RCIC and HPCI	See BWR loss-of-main-feedwater entry.								
Failure of ADS/LPCI/CS	The ADS failure estimate of 2.7 x 10^{-2}/D is assumed to dominate the failure probability.								
Failure of long-term core cooling	See BWR loss-of-main-feedwater entry.								
					BWR loss-of-coolant accident				
Initiating event	66966	Oct. 10, 1971	Millstone 1	349	The turbine control system malfunctioned and caused a transient that resulted in a relief valve failing to reset. About 75,000 gal of reactor coolant blew out of the system.	1.0	3.1		148 post-l plant year
	77961	Dec. 29, 1972	Oyster Creek	1334	An operator opened a cabinet door housing protective fuses for the generator monitoring relays, thus causing a reactor scram. Pressure was being controlled using relief valves when one failed open resulting in the blowdown of ~50,000 gal of reactor coolant.	1.0			

Table C.1 (continued)

Event description Plant	Plant age (d)	Description	Severity	Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions	Initiating event frequency estimate (per year)	Demand failure probability estimate (per demand) Minimum function	 Maximum function	Value used in ASP calculations
Hatch 1	87	Two DGs malfunction during testing	1.0	8.0	10.0	12 per plant year due to testing plus 11 LOOPs, which result in 1786 total demands.		4.5×10^{-3}	5.6×10^{-3}	5.0×10^{-3}/D
Hatch 1	464	Two DGs fail to start during testing	1.0							
Brunswick 1	87	Two DGs trip during surveillance testing	1.0							
Dresden 3	2273	DG fields failed to flash	1.0							
Peach Bottom 2	1443	Two DGs fail to start during testing	1.0							
Dresden 3	2493	DGs trip during testing	1.0							
Dresden 2	2890	DGs fail to start (potential demand failure)	1.0							
Peach Bottom 2	1041	Three of four DGs rendered inoperable due to improper maintenance (potential demand failure)	1.0							
Millstone 1	2616	DG and gas-turbine generator failed during testing	1.0							
Dresden 2	3473	Failure of 2 DGs during testing	1.0							
to be the dominant contributor to this failure probability. Failure to s assumed to be equivalent to failure to initiate AFW manually as re- p. 22-14 through 22-19). This value is taken as 5×10^{-3}/D.										5×10^{-3}/D
ater entry.										
f 2.7×10^{-2}/D is assumed to dominate the failure probability.										-2
ater entry.										
BWR loss-of-coolant accident										
Millstone 1	349	The turbine control system malfunctioned and caused a transient that resulted in a relief valve failing to reset. About 75,000 gal of reactor coolant blew out of the system.	1.0	3.1		148 post-1968 plant years	2.1×10^{-2}			2.1×10^{-2}/year
Oyster Creek	1334	An operator opened a cabinet door housing protective fuses for the generator monitoring relays, thus causing a reactor scram. Pressure was being controlled using relief valves when one failed open resulting in the blowdown of ~50,000 gal of reactor coolant.	1.0							

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Table C.1 (continued)

Initiating event/function under consideration	Event description						Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions
	NSIC accession number	Event date	Plant	Plant age (d)	Description	Severity			
	105540	Aug. 17, 1975	Quad Cities	1208	A reactor startup was under way when extreme vibration of the feedwater pump occurred. This resulted in the low-flow feedwater line severing at the 6 x 4 in. reducer. The line was isolated.	0.1			
	128569	July 15, 1977	Brunswick 2	281	A turbine trip caused a reactor scram. A relief valve lifted to control the reactor pressure, but it failed to reset. Both RCIC and HPCI were required to maintain a satisfactory coolant inventory.	1.0			
Failure of HPCI	A search of the HPCI LER data base was done using RECON at ORNL. Based on analysis of abstracts identified in this search, 76 events considered unrectifiable were identified. Eleven additional potential demand failures were also identified. These events are part of the BWR High-Pressure Coolant Injection System Failures (this appendix).						76.0	87.0	12 due to testing plus 2 due to startup testing plus 0.58 LOFW events per HPCI plant year, which result in 1433 estimated demands.
Failure of long-term core cooling for LOCA	See BWR loss-of-feedwater entry.								
					BWR main steam line break				
BWR main steam line break	Value assumed was 1×10^{-4}/year. This is equivalent to the estimate of a large LOCA reported in WASH-1400 (main report, p. 81).								
Failure of reactor vessel isolation	60227	Dec. 4, 1970	Dresden 2	331	Several MSIVs failed to close during a full closure test.	1.0	1.0		1 due to full closure test plus 0.58 LOFW events per year plus 11 LOOPs, which result in 336 total estimated demands.
Failure of reactor scram	See BWR loss-of-main-feedwater entry.								
Failure of RCIC and HPCI	See BWR loss-of-main-feedwater entry.								
Failure of ADS/LPCI/CS	See BWR loss-of-offsite-power entry.								
Failure of long-term core cooling	See BWR loss-of-main-feedwater entry.								

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[a] A rectification value of 0.5 was assumed based on the percentage of LOOPs recovered in less than 30 min. Source: Frank Clark, personal communication on ORNL study on station blackout

[b] Combined value based on BWR and PWR LOOPs.

Table C.1 (continued)

tion t)			Total number of events × severity	Total number of events and potential events × severity	Observation period or demands assumptions	Initiating event frequency estimate (per year)	Demand failure probability estimate (per demand)		Value used in ASP calculations
	Description	Severity					Minimum function	Maximum function	
8	A reactor startup was under way when extreme vibration of the feedwater pump occurred. This resulted in the low-flow feedwater line severing at the 6 x 4 in. reducer. The line was isolated.	0.1							
1	A turbine trip caused a reactor scram. A relief valve lifted to control the reactor pressure, but it failed to reset. Both RCIC and HPCI were required to maintain a satisfactory coolant inventory.	1.0							
N at ORNL. Based on analysis of abstracts ifiable were identified. Eleven additional events are part of the BWR High-Pressure			76.0	87.0	12 due to testing plus 2 due to startup testing plus 0.58 LOFW events per HPCI plant year, which result in 1433 estimated demands.		5.3×10^{-2}	6.1×10^{-2}	5.7×10^{-2}/D
	BWR main steam line break								
o the estimate of a large LOCA reported in									1.0×10^{-4}/ year
1	Several MSIVs failed to close during a full closure test.	1.0	1.0		1 due to full closure test plus 0.58 LOFW events per year plus 11 LOOPs, which result in 336 total estimated demands.				3.0×10^{-3}/D

covered in less than 30 min. Source: Frank Clark, personal communication on ORNL study on station blackouts, November 1981.

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BWR High-Pressure Coolant Injection System Failures

ACCESSION NUMBER 84195

FAILURE OF HPCI SYSTEM DURING AN AUTOMATIC QUICK START AT BROWNS FERRY 1 (BFAO-7311W)
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
2 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), SEPTEMBER 20, 1973.
DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA
DURING INITIAL STARTUP TESTING AT 150 PSIG, THE HIGH-PRESSURE COOLANT-INJECTION SYSTEM FAILED TO REACH RATED SPEED AND FLOW DURING A SIMULATED QUICK START. THE FLOW-CONTROLLER AMPLIFIER PLUG-IN WAS COCKED SO THAT A PORTION WAS DISCONNECTED. AN ANCHOR NUT ON ONE END WAS MISSING. LOCKING MATERIAL WILL BE INSTALLED ON ALL SIMILAR GE/MAC CONTROLLER-RECEPTACLE FASTENER NUTS.

ACCESSION NUMBER 85566

COMPLETE LOSS OF PLANT AC POWER CAUSED RCIC AND HPCI TO BE INOPERABLE AT BROWNS FERRY 1 (BFAO-7334W)
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
3 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), NOVEMBER 19, 1973.
DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA
IN PREPARING FOR A STARTUP TEST (TURBOGENERATOR TRIP AND LOSS OF OFF-SITE POWER) THE 4-KV UNIT BOARDS WERE PLACED IN 'MANUAL' TO PREVENT AUTOMATIC TRANSFER. THE TURBINE WAS TRIPPED MANUALLY BECAUSE OF INCREASED VIBRATION, CAUSING A SCRAM SINCE OFF-SITE POWER COULD NOT BE SUPPLIED. THE RCIC AND HPCI SYSTEMS COULD NOT BE STARTED UNTIL THE STANDBY GENERATORS ENERGIZED AND THE TRIPPING LOGIC FOR THE SYSTEMS HAD BEEN MANUALLY RESET. REVISIONS ARE UNDER WAY TO ELIMINATE THE MANUAL RESET AND TO CHANGE THE POWER SOURCE FOR SOME RELAYS.

ACCESSION NUMBER 85738

RCIC AND HPCI FAILURES DURING TESTING AT BROWNS FERRY 1 (BFAO-7338W)
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
3 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), NOVEMBER 23, 1973.
DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA
DURING STARTUP TESTING, THE REACTOR CORE ISOLATION COOLING SYSTEM FAILED TO OPERATE WHEN MANUALLY INITIATED. THE STEAM SUPPLY VALVE FAILED TO OPEN BECAUSE A MOVABLE CONTACT OF THE DC CONTACTOR WAS HUNG IN THE ARCING HORN. THE VALVE WAS REPAIRED. WHEN THE RCIC FAILED, THE HPCI WAS MANUALLY INITIATED TO MAINTAIN THE VESSEL WATER LEVEL. IT ISOLATED AND TRIPPED. THE ISOLATION CIRCUIT WAS IMMEDIATELY RESET AND THE HPCI FUNCTIONED PROPERLY. NO CAUSE FOR THE TRIP HAS BEEN FOUND.

ACCESSION NUMBER 87287

FAILURE OF HPCI VALVE AT PILGRIM FROM BURNED OUT MOTOR UO 73-17
BOSTON EDISON COMPANY
1 PAGE, LETTER TO DIRECTORATE OF LICENSING (AEC), NOVEMBER 30, 1973.
DOCKET 50-293, TYPE--BWR, MFG--G.E., AE--BECHTEL
DURING A TEST OF THE HIGH PRESSURE COOLANT INJECTION SYSTEM, THE TURBINE STEAM SUPPLY VALVE FAILED TO OPEN. THE VALVE WAS JAMMED IN THE CLOSED POSITION AND THE MOTOR WAS BURNED OUT. THE VALVE WAS OPENED AND THE MOTOR WAS REPLACED. THE VALVE THEN OPERATED PROPERLY. NO CAUSE OF FAILURE WAS DETERMINED.

ACCESSION NUMBER 88758

HPCI FAILURE TO PUMP TO VESSEL AT BROWNS FERRY 1 (BFAO-747W)
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
3 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), FEBRUARY 5, 1974, DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA
AS PART OF THE STARTUP TEST PROGRAM WITH THE REACTOR AT 45% POWER, THE HCPI SYSTEM WAS STARTED. THE PUMP FLOW AND TURBINE SPEED WERE VERY UNSTABLE. THE TEST WAS ABORTED. ARCING WAS OBSERVED AT A LIMIT SWITCH IN THE MOTOR-OPERATED HPCI STEAM SUPPLY VALVE TO THE TURBINE. A MOTOR LEAD WAS GROUNDED. THE FLOW INSTABILITY WAS A RESULT OF A HIGH GAIN SETTING ON THE FLOW CONTROLLER MAKING THE TURBINE RESPONSE TOO SENSITIVE. THE GAIN WAS DECREASED. A LOSS OF SPEED INDICATION OCCURRED AS A RESULT OF A SHORT INSIDE THE EGM GOVERNOR CONTROL BOX. THE SHORT WAS REPAIRED. THIS WAS THE FIRST OPERATION OF THE HPCI SYSTEMS.

ACCESSION NUMBER 88126

FAILURE OF HPCI SYSTEM AT BROWNS FERRY 1 FROM FAULTY RESISTOR (BFAO-7348W)
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
2 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), JANUARY 4, 1974, DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA
WHILE THE REACTOR WAS OPERATING AT 1580 MWT, THE HPCI SYSTEM FAILED TO START PROPERLY DURING A TEST. A RESISTOR WAS OPEN IN THE WOODWARD UNIT WHICH SUPPLIES THE 48 V DC POWER TO THE EG-M GOVERNOR CONTROL BOX. THE GOVERNOR WAS UNABLE TO GIVE THE PROPER SIGNAL TO THE CONTROL VALVE. AFTER THE RESISTOR BOX WAS REPLACED, THE HPCI SYSTEM OPERATED PROPERLY.

ACCESSION NUMBER 89508

HPCI FAILURE AT BROWNS FERRY 1
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
3 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), MARCH 21, 1974, DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA
CAUSE - CONTROL BOX FAILURE. THE HPCI TURBINE FAILED TO REACH RATED SPEED AND FLOW DURING TESTING. THE AUXILIARY OIL PUMP WAS CYCLING ON AND OFF. THE REACTOR WAS AT 1533 MWT. THE APPARENT CAUSE WAS THE INABILITY OF THE GOVERNOR TO RESPOND WHEN AN INCREASE IN SPEED WAS CALLED FOR. THE EGM CONTROL BOX TO THE GOVERNOR ACTUATOR WAS REPLACED. THE HPCI THEN OPERATED PROPERLY. THE CAUSE OF FAILURE HAS NOT BEEN DETERMINED.

ACCESSION NUMBER 89737

MALFUNCTION OF RELIEF VALVES AND HPCI SYSTEM AT PEACH BOTTOM 2
PHILADELPHIA ELECTRIC COMPANY
4 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), APRIL 4, 1974, DOCKET 50-277, TYPE--BWR, MFG--G.E., AE--BECHTEL
CAUSE - FAILURE OF COMPONENTS. FOLLOWING VENDOR RECOMMENDED MODIFICATIONS ON ALL RELIEF VALVES, TESTS AT 950 PSIG SHOWED 2 VALVES TO HAVE BELLOWS ASSEMBLY LEAKS AND ONE INOPERABLE. TESTING OF THE HPCI SYSTEM FOUND THE TURBINE CONTROL VALVE DEFECTIVE. THE MALFUNCTION IN THE HPCI SYSTEM WAS TRACED TO A LOCAL SPEED CONTROL POTENTIOMETER WHICH WAS OPEN CIRCUITED. THE SLIDE WIRE STOPS FAILED TO STOP MOVEMENT. THE POTENTIOMETER WAS REPLACED. THE VALVE LEAKS WERE THROUGH THE O-RING SEALS. A THIRD WERE REPLACED. NO CAUSE WAS FOUND FOR FAILURE OF THE ONE VALVE TO OPERATE.

ACCESSION NUMBER 91179

HPCI TURBINE ISOLATION AT PEACH BOTTOM 2
PHILADELPHIA ELECTRIC COMPANY
4 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), MAY 7, 1974, DOCKET 50-277, TYPE--BWR, MFG--G.E., AE--BECHTEL

CAUSE - RAPID OPENING OF STOP VALVE. AS PART OF THE STARTUP TEST PROGRAM, HPCI COLD QUICK START VESSEL INJECTION TESTING WAS PERFORMED. FOLLOWING THE COLD QUICK START INITIATION, AN HPCI TURBINE ISOLATION OCCURRED FROM HIGH STEAM FLOW. INVESTIGATION SHOWED THAT THE STOP VALVE OPENING SPEED WAS SIGNIFICANTLY FASTER DURING THIS STARTUP THAN ON A HOT STARTUP. DURING LONG PERIODS OF SHUTDOWN, AIR ACCUMULATES IN THE HYDRAULIC CYLINDER OF THE STOP VALVE. THIS PRODUCES RAPID VALVE MOTION AFTER THE PILOT VALVE RELEASES THE AIR. A PIPING CORRECTION WILL BE MADE TO CORRECT THE AIR INLEAKAGE.

ACCESSION NUMBER 91673

FAILURE OF HPCI SYSTEM AT BROWNS FERRY 1
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
3 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), MAY 15, 1974, DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA

CAUSE - UNKNOWN. STARTUP TESTING WHICH AFFECTED THE FEEDWATER SYSTEM RESULTED IN A SCRAM FROM 92% POWER. THE HPCI SYSTEM WAS INITIATED BY LOW WATER LEVEL. THE SYSTEM STARTED BUT TRIPPED OFF. IT WAS PLACED ON MANUAL CONTROL AND USED TO REGULATE THE VESSEL WATER LEVEL. AFTER IT WAS SHUT DOWN, THE INVERTER POWER SUPPLY FUSE WAS FOUND TO BE BLOWN. NO CAUSE FOR THE HPCI TRIP WAS FOUND. ONE POSSIBILITY WAS OVERSPEED. ALSO, NO CAUSE WAS FOUND FOR THE FUSE BEING BLOWN.

ACCESSION NUMBER 92447

HPCI ISOLATION AT BROWNS FERRY 1
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
2 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC); JUNE 5, 1974, DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA

CAUSE - MOTOR FAILURE. DURING TESTING WITH THE REACTOR AT 37% POWER, THE HPCI SYSTEM ISOLATED ON HIGH STEAM FLOW. FOLLOWING THIS, THE INBOARD CONTAINMENT ISOLATION VALVE COULD NOT BE REOPENED. THE REACTOR WAS SHUT DOWN. THE VALVE MOTOR OPERATOR WAS BADLY BURNED AND ONE GEAR TOOTH WAS BROKEN IN THE GEAR MECHANISM. THE CAUSE WAS UNDETERMINED. THE HIGH STEAM FLOW CONDITIONS OCCUR WHEN THE HPCI IS IDLE FOR AT LEAST 68 HOURS WITHOUT USE. WHEN TESTED DAILY, HIGH FLOW DOES NOT OCCUR.

ACCESSION NUMBER 92635

HPCI VALVE FAILS TO OPEN AT DRESDEN 3
COMMONWEALTH EDISON COMPANY
2 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), JUNE 10, 1974, DOCKET 50-249, TYPE--BWR, MFG--G.E, AE--SGT & LUNDY

CAUSE - BREAKER ADJUSTMENT. DURING TESTING IN THE PROCESS OF UNIT STARTUP, A HPCI VALVE FAILED TO OPEN. THE MAIN CONTACTOR IN THE SUPPLY BREAKER FOR THE VALVE FAILED TO PICK UP DUE TO LACK OF CLEARANCE BETWEEN THE AUX CONTACT OPERATING BAR AND THE MAIN CONTACT ARMATURE ROLLER. THIS CLEARANCE WAS ADJUSTED AS WELL AS THE AIR GAP BETWEEN THE MAIN CONTACTOR ARMATURE AND THE MAIN CONTACTOR COIL. MAINTENANCE PROCEDURES WERE CHANGED FOR MAKING THESE ADJUSTMENTS.

ACCESSION NUMBER 93735

HPCI TURBINE FAILS TO START MANUALLY AT BROWNS FERRY 1
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
3 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC); JUNE 19, 1974, DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA
CAUSE - VALVE MALFUNCTION. DURING STARTUP TESTING, SEVERAL ATTEMPTS WERE MADE TO MANUALLY START THE HPCI SYSTEM. DURING EACH ATTEMPT THE TURBINE STOP VALVE DID NOT FULLY OPEN. ONLY THE STOP PILOT VALVE OPENED. THE OIL RELAY VALVE PISTON, PISTON RINGS, AND COMPRESSION SPRING HAD A NUMBER OF SMALL SCRATCHES AND SCORES WHICH COULD CAUSE THE RELAY VALVE TO STICK AND NOT SEAT PROPERLY. AFTER THE PARTS WERE POLISHED, THE HPCI STARTED SATISFACTORILY ON 6 CONSECUTIVE TESTS.

ACCESSION NUMBER 94868

HPCI TURBINE STOP VALVE FAILS TO OPEN AT MONTICELLO
NORTHERN STATES POWER COMPANY
4 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), AUGUST 16, 1974, DOCKET 50-263, TYPE--BWR, MFG--G.E., AE--BECHTEL
CAUSE - TRIP RESET SPRING RELAXATION. DURING TESTING OF THE HPCI AUXILIARY OIL PUMPS WHILE THE REACTOR WAS AT 83.9% POWER, THE HPCI TURBINE STOP VALVE WAS OBSERVED TO PARTIALLY OPEN AND THEN CLOSE. BECAUSE OF THE INTERMITTENT NATURE OF THE PROBLEM, IT WAS NOT POSSIBLE TO DETERMINE A DEFINITE CAUSE. HOWEVER, IT IS POSTULATED THAT THE TURBINE OVERSPEED TRIP RESET SPRING RELAXED ALLOWING THE TRIP PISTON TO LIFT DURING SLIGHT PRESSURE SURGES. THE SPRING TENSION WAS TIGHTENED. AIR WAS BLED FROM THE OIL SYSTEM TO REDUCE PRESSURE SURGES.

ESSION NUMBER 94924

HPCI INJECTON VALVE FAILS TO OPERATE AT ARNOLD
IOWA ELECTRIC LIGHT AND POWER COMPANY
4 PAGES, LETTER WITH ATTACHED ABNORMAL OCCURRENCE REPORT 50-331/74-22 TO DIRECTORATE OF REGULATORY OPERATIONS (AEC), REGION III, JULY 25, 1974, DOCKET 50-331, TYPE--BWR, MFG--G.E., AE--COMMONWEALTH ASSOC.
CAUSE - MAINTENANCE ERROR. DURING TWO TESTS, THE HPCI INJECTION VALVE MALFUNCTIONED. THE FIRST EVENT WAS CAUSED BY THE SLOW OPENING OF THE HPCI TURBINE STOP VALVE. THE BYPASS VALVE AROUND THE HYDRAULIC OPERATING CYLINDER OF THE STOP VALVE WAS ADJUSTED TO PROVIDE THE PROPER OPENING SPEED. THE SECOND EVENT RESULTED FROM FAILURE OF A RELAY TO OPERATE. THIS MALFUNCTION WAS CAUSED BY MOISTURE IN A JUNCTION BOX.

ACCESSION NUMBER 94925

HPCI FAILS TO INJECT INTO THE VESSEL AT ARNOLD
IOWA ELECTRIC LIGHT AND POWER COMPANY
4 PAGES, LETTER TO DIRECTORATE OF REGULATORY OPERATIONS (AEC), REGION III, JULY 22, 1974, DOCKET 50-331, TYPE--BWR, MFG--G.E., AE--COMMONWEALTH ASSOC.
CAUSE - TRIP DEVICE MALFUNCTION. DURING TESTING, THE HPCI SYSTEM DID NOT INJECT INTO THE VESSEL ON 2 OCCASSIONS. AFTER THE FIRST INCIDENT, THE OIL RELIEF VALVE WAS ADJUSTED. AFTER THE SECOND INCIDENT, A MECHANICAL OVERSPEED TRIP DEVICE WAS FOUND TO HAVE AN UNDERSIZED PISTON WHICH CAUSED MOMENTARY TRIP SIGNALS. THE PISTON WAS REPLACED WITH ONE OF THE PROPER SIZE. THIS MALFUNCTION HAD CAUSED BOTH FAILURES.

ACCESSION NUMBER 94927

HPCI SUBSYSTEM FAILS TO INJECT AT ARNOLD
IOWA ELECTRIC LIGHT AND POWER COMPANY
2 PAGES. LETTER TO DIRECTORATE OF REGULATORY OPERATIONS (AEC), REGION III, JULY 8, 1974, DOCKET 50-331, TYPE--BWR, MFG--G.E., AE--COMMONWEALTH ASSOC.
CAUSE - SHORTED LIMIT SWITCH. DURING A TEST, THE HPCI SUBSYSTEM FAILED TO INJECT. TENTATIVE CAUSE WAS ATTRIBUTED TO WATER SHORTING A LIMIT SWITCH IN A JUNCTION BOX AT HPCI STEAM SUPPLY VALVE.

ACCESSION NUMBER 95039

HPCI EXHAUST LINE RUPTURE DISC FAILS AS BROWNS FERRY 2
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
3 PAGES. LETTER WITH ABNORMAL OCCURRENCE REPORT 50-260/745W TO DIRECTORATE OF LICENSING (AEC), AUG. 21, 1974, DOCKET 50-260, TYPE--BWR, MFG--G.E., AE--TVA
CAUSE - WATER IN THE LINE. DURING A MANUAL START OF HPCI WITH THE REACTOR AT 5% POWER, THE TURBINE EXHAUST LINE RUPTURE DISC FAILED RESULTING IN HPCI ISOLATION. FAILURE MAY HAVE RESULTED FROM WATER IN THE LINE. THE SOLENOID COIL OF THE EXHAUST LINE DRAIN VALVE WAS BURNED UP. WIRING ERRORS WERE FOUND IN THE VALVE SWITCH AND IN THE LEVEL SWITCH WHICH KEPT THE SOLENOID ENERGIZED. BOTH ERRORS CAUSED THE VALVE TO BE OPEN WHEN IT SHOULD BE CLOSED AND CLOSED WHEN IT SHOULD BE OPEN. THE RUPTURE DISC AND SOLENOID COIL WERE REPLACED AND THE WIRING ERRORS CORRECTED.

ACCESSION NUMBER 95040

HPCI INJECTION VALVES AND RCIC FAIL AT BROWNS FERRY 2
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
2 PAGES. LETTER TO DIRECTORATE OF LICENSING (AEC), AUGUST 23, 1974. DOCKET 50-260, TYPE--BWR, MFG--G.E., AE--TVA
CAUSE - UNKNOWN. DURING TESTING WITH THE REACTOR AT 5% POWER, A HPCI INJECTION VALVE FAILED TO OPEN. DURING POSTMAINTENANCE TESTING OF THIS VALVE, A SECOND VALVE ALSO FAILED TO OPEN. FOLLOWING THE VALVE FAILURE, RCIC FAILED TO SHOW ANY SPEED INDICATION WHEN THE TURBINE WAS MANUALLY INITIATED. THE SEAT WAS WEDGED TIGHTLY INTO BOTH VALVE BODIES. SEVERAL BOLTS THAT HOLD THE VALVE OPERATORS IN PLACE WERE BROKEN. NO CAUSE WAS FOUND. THE DAMAGED PARTS WERE REPLACED AND REPLACEMENT OPERATORS INSTALLED. A DAMAGED TACHOMETER PRINTED CIRCUIT BOARD ON THE RCIC WAS REPLACED.

ACCESSION NUMBER 95591

HPCI FAILS TO START AT BROWNS FERRY 1
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
2 PAGES. LETTER TO DIRECTORATE OF LICENSING (AEC), SEPTEMBER 27, 1974. DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA
CAUSE - RELAY DRAGGING. DURING A TEST WHILE THE REACTOR WAS AT 95% POWER, THE HPCI FAILED TO START ON THE FIRST ATTEMPT. THE MOVABLE CONTACT OF THE AUXILIARY OIL PUMP MOTOR CONTACTOR WAS DRAGGING AGAINST THE INSIDE OF THE ARC CHUTE. IT IS BELIEVED TO HAVE PREVENTED THE AUXILIARY OIL PUMP MOTOR FROM STARTING. THE MOVABLE AND STATIONARY CONTACTS WERE CLEANED AND REALIGNED. THE HPCI THEN FUNCTIONED SATISFACTORILY.

ACCESSION NUMBER 95912

HPCI TURBINE BEARING FAILURE AT PEACH BOTTOM 3
PHILADELPHIA ELECTRIC CO., PA
2 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), SEPT. 28, 1974, DOCKET 50-278, TYPE--BWR, MFG--G.E., AE--BECHTEL
CAUSE - IMPROPER LUBRICATION. DURING HPCI TURBINE TEST OPERATION, A SMALL STEAM LEAK WAS NOTED AT THE PUMP END TURBINE SHAFT PACKING. THE BEARING HAD WIPED RESULTING IN A DOWNWARD DISPLACEMENT OF THE TURBINE SHAFT. THIS SHAFT DISPLACEMENT RESULTED IN DAMAGE TO THE CARBON RING STEAM PACKING. FAILURE PROBABLY WAS DUE TO INSUFFICIENT OIL SUPPLY TO THE BEARING. IT IS THOUGHT THAT A TEMPORARY FLOW BLOCAKGE HAD OCCURRED THAT CLEARED ITSELF. THE TURBINE ROTOR SHAFT AND BOTH BEARINGS WERE REPLACED. THE OIL SYSTEM WAS CLEANED AND FLUSHED.

ACCESSION NUMBER 97073

HPCI SYSTEM INOPERABLE AT BROWNS FERRY 2
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA
2 PAGES, LETTER WITH ABNORMAL OCCURRENCE REPORT 7424W TO DIRECTORATE OF LICENSING (AEC), NOV. 14, 1974, DOCKET 50-260, TYPE--BWR, MFG--G.E., AE--TVA
CAUSE - GLAND STEAM CONDENSER GASKET LEAK. THE HPCI SYSTEM WAS AUTOMATICALLY INITIATED FOLLOWING A REACTOR SCRAM. A SHORT TIME LATER, THE HPCI ROOM WAS INSPECTED AND NO LEAKS WERE NOTED. LATER STILL, BOTH THE UPPER AND LOWER HEAD GASKETS ON THE GLAND STEAM CONDENSER STARTED LEAKING. THE GLAND STEAM CONDENSER HOTWELL PUMP AND MOTOR WERE FLOODED. BOTH GASKETS WERE REPLACED. THE MOTOR WAS DRIED OUT AND MEGGERED SATISFACTORILY. A CLAMPING RING WITH A GASKET TO SUPPORT THE PRESENT GASKET IS BEING CONSIDERED.

ACCESSION NUMBER 97718

HPCI VALVE FAILS TO OPEN AT DRESDEN 2
COMMONWEALTH EDISON COMPANY, ILLINOIS
3 PAGES, LETTER TO DIRECTORATE OF REGULATORY OPERATIONS (AEC), REGION III, NOV. 22, 1974, DOCKET 50-237, TYPE--BWR, MFG--G.E., AE--SGT & LUNDY
CAUSE - TERMINAL BLOCK FAILURE. DURING THE REFUELING OUTAGE THE OPERATOR TRIED UNSUCCESSFULLY TO OPEN THE VALVE THAT ALLOWS THE HPCI PUMP TO TAKE SUCTION FROM THE CONDENSATE STORAGE TANKS. IT APPEARS THAT A FLAW EXISTED IN THE INSULATING BARRIER BETWEEN 2 TERMINAL POSTS ON THE TERMINAL BLOCK FOR THE SHUNT FIELD. WHEN THE VALVE WAS OPERATED, THE FLAW ALLOWED THE 250 VDC TO ARC ACROSS THE TERMINAL POSTS. THIS BURNED AWAY THE TWO TERMINAL STRIPS. A NEW TERMINAL BLOCK WAS INSTALLED AND THE WIRES WERE REPLACED. THE VALVE IS A NORMALLY OPEN VALVE.

ACCESSION NUMBER 97853

HPCI VALVE FAILS TO OPEN AT PILGRIM
BOSTON EDISON COMPANY, MASSACHUSETTS
2 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), DECEMBER 8, 1974, DOCKET 50-293, TYPE--BWR, MFG--G.E., AE--BECHTEL
CAUSE - VALVE DAMAGED. DURING TESTING OF THE HIGH PRESSURE COOLANT INJECTION SYSTEM WHILE THE REACTOR WAS IN THE HOT SHUTDOWN CONDITION, A MOTOR OPERATED VALVE DID NOT OPEN ON SIGNAL FROM THE CONTROL ROOM. THE VALVE MOTOR HAD OVERLOADED WHILE ATTEMPTING TO OPEN THE VALVE. THIS IS THE FOURTH FAILURE OF THIS MOTOR. THE VALVE STEM WAS FOUND TO BE DAMAGED IN THE BACK SEAT AND ALONG THE PACKING AREA. REPAIRS WERE MADE AND THE MOTOR WAS REPLACED IN KIND.

ACCESSION NUMBER 97855

HPCI VALVE FAILS TO OPEN AT PILGRIM
BOSTON EDISON COMPANY, MASSACHUSETTS
2 PAGES, LETTER TO DIRECTORATE OF LICENSING (AEC), DECEMBER 6, 1974,
DOCKET 50-293, TYPE--BWR, MFG--G.E., AE--BECHTEL
CAUSE - MOTOR OVERLOADED. DURING TESTING WHILE THE REACTOR WAS AT 91% POWER, A HIGH PRESSURE COOLANT INJECTION VALVE DID NOT OPEN WHEN GIVEN AN OPEN SIGNAL FROM THE CONTROL ROOM. THE VALVE MOTOR HAD OVERLOADED WHILE ATTEMPTING TO OPEN THE VALVE. SIMILAR FAILURES HAVE BEEN EXPERIENCED. THE VALVE MOTOR WAS REPLACED IN KIND.

ACCESSION NUMBER 99264

HPCI SYSTEM VALVE FAILS TO OPEN AT FITZPATRICK
NIAGARA MOHAWK POWER CORPORATION, NEW YORK
2 PAGES, LETTER WITH AO REPORT 74/37 TO DIRECTORATE OF LICENSING (AEC),
JANUARY 6, 1975, DOCKET 50-333, TYPE--BWR, MFG--G.E., AE--STONE & WEBSTER
CAUSE - TORQUE SWITCH SET IMPROPERLY. DURING STARTUP TEST PROGRAM WHILE PREPARING TO WARM UP HPCI STEAM LINE, THE TURBINE STEAM SUPPLY VALVE WOULD NOT OPEN FROM THE CONTROL ROOM. THE REACTOR WAS IN HOT STANDBY. THE TORQUE SWITCH WAS MISADJUSTED DURING INSTALLATION. IT WAS READJUSTED. THE VALVE WAS CYCLED 3 TIMES.

ACCESSION NUMBER 102163

HPCI VALVE OPERATOR FAILS AT BRUNSWICK 2
CAROLINA POWER & LIGHT COMPANY
2 PAGES, LETTER WITH AO REPORT 75/4 TO U.S. NRC, REGION 2, APRIL 4, 1975,
DOCKET 50-324, TYPE--BWR, MFG--G.E., AE--UE+C
CAUSE - PINCHED WIRE. DURING A QUICK START TEST OF HPCI, AFTER RUNNING NORMALLY AT RATED FLOW, A LOW FLOW ALARM WAS RECEIVED. THE HPCI PUMP DISCHARGE VALVE WAS FOUND TO BE FULLY CLOSED AND THE VALVE FUSES BLOWN. A PINCHED WIRE RESULTED IN A VALVE MOTOR OPERATOR GROUND WHICH CAUSED THE VALVE TO CLOSE. THE WIRE WAS REPAIRED AND THE VALVE RETURNED TO SERVICE.

ACCESSION NUMBER 102549

HPCI SYSTEM CONTROL VALVE FAILS TO OPEN AT QUAD CITIES 2
COMMONWEALTH EDISON COMPANY, ILLINOIS
3 PAGES, LETTER WITH AOR 75-14 TO NRC DIRECTORATE OF LICENSING REGULATION, APRIL 28, 1975, DOCKET 50-265, TYPE--BWR, MFG--G.E., AE--SGT & LUNDY
CAUSE - PRESSURE SWITCH SETTING LOW. DURING ECCS TESTING WITH THE UNIT SHUTDOWN FOR REFUELING, THE HPCI SYSTEM FAILED TO START. THE HPCI AUXILIARY OIL PUMP WAS CYCLING ON AND OFF AND THE EMERGENCY PUMP STARTED. THE OPERATOR MANUALLY STARTED THE AUXILIARY OIL PUMP AND THE HPCI SYSTEM STARTED SUCCESSFULLY. DUE TO PRESSURE SWITCH SETTINGS, THE EMERGENCY OIL PUMP STARTED ON LOW PRESSURE ON THE BEARING LUBRICATION HEADER. THIS RAISED THE PRESSURE ON THE HYDRAULIC CONTROL SYSTEM HEADER TO TURN THE AUXILIARY PUMP OFF. THIS DROPPED HYDRAULIC CONTROL SYSTEM HEADER PRESSURE CAUSING THE AUXILIARY PUMP TO RESTART. PRESSURE SWITCH SETTINGS WERE ADJUSTED.

ACCESSION NUMBER 102894

HPCI SYSTEM INOPERABLE AT QUAD CITIES 1
COMMONWEALTH EDISON COMPANY, ILLINOIS
3 PAGES, LETTER WITH AOR 75-13 TO NRC OFFICE OF NUCLEAR REACTOR REGULATION, MAY 13, 1975, DOCKET 50-254, TYPE--BWR, MFG--G.E., AE--SGT & LUNDY
CAUSE - MOTOR SPEED CHANGER MALFUNCTION. DURING AN RCIC OUTAGE SURVEILLANCE TEST OF THE HPCI SYSTEM, IT WAS FOUND THAT THE HPCI MOTOR SPEED CHANGER WOULD NOT OPERATE. AN ORDERLY SHUTDOWN FROM 527 MWE WAS INITIATED AT THE RATE OF 12 MWE/HR. WHEN THE SPEED CHANGER WAS REMOVED FROM ITS MOUNTING, IT WAS FOUND TO OPERATE. IT WAS REPLACED IN ITS MOUNTING AND OPERATED REPEATEDLY WITHOUT ANY RECURRENCE OF THE PROBLEM.

ACCESSION NUMBER 103196

HPCI TURBINE TRIPS AT FITZPATRICK
NIAGARA MOHAWK POWER CORP., N.Y.
2 PAGES, LETTER WITH AO 75-46 TO NRC DIRECTORATE OF LICENSING, MAY 29, 1975, DOCKET 50-333, TYPE--BWR, MFG--G.E., AE--STONE & WEBSTER
CAUSE - LOW OIL PRESSURE. THE HPCI TURBINE TRIPPED ON LOW OIL PRESSURE WHILE CONDUCTING REACTOR STARTUP TESTING. THE CAUSE IS BEING INVESTIGATED. AFTER THE HPCI TURBINE AUXILIARY OIL PUMP WAS RUN FOR 10 MINUTES, THE TEST WAS REPEATED SUCCESSFULLY. IT APPEARS THAT OIL PRESSURE AND LEVEL HAD BEEN REDUCED SUFFICIENTLY PREVENTING THE MAIN TURBINE OIL PUMP FROM STARTING. LEAKS WERE FOUND IN THE OIL SYSTEM AND WILL BE REPAIRED. THE AUXILIARY PUMP WILL BE OPERATED INTERMITTENTLY TO KEEP THE OIL LEVEL UP.

ACCESSION NUMBER 103545

HPCI VALVE FAILS TO OPEN AT PILGRIM
BOSTON EDISON COMPANY, MASS.
2 PAGES, LETTER WITH UU 75-9 TO NRC OFFICE OF NUCLEAR REACTOR REGULATION, JUNE 7, 1975, DOCKET 50-293, TYPE--BWR, MFG--G.E., AE--BECHTEL
CAUSE - MOTOR OVERLOADED. A HPCI MOTOR OPERATED VALVE DID NOT OPEN WHEN GIVEN A SIGNAL FROM THE CONTROL ROOM. THE VALVE MOTOR OVERLOADED WHILE ATTEMPTING TO OPEN THE VALVE. THE VALVE WAS REPAIRED ON THE SAME DAY. THE REACTOR WAS AT 60% POWER.

ACCESSION NUMBER 104970

HEAD GASKET ON GLAND SEAL EXHAUST CONDENSER FAILS AT VERMONT YANKEE
VERMONT YANKEE NUCLEAR POWER CORP., RUTLAND
3 PAGES, LETTER WITH AOR 75-14 TO NRC OFFICE OF INSPECTION & ENFORCEMENT, REGION 1, AUG. 6, 1975, DOCKET 50-271, TYPE--BWR, MFG--G.E., AE--EBASCO
CAUSE - OVERPRESSURIZED DURING START. DURING A HPCI SYSTEM PUMP OPERABILITY TEST WITH THE REACTOR AT 80% POWER, THE HEAD GASKET ON THE GLAND SEAL EXHAUST CONDENSER FAILED. THIS PRECLUDING HPCI OPERABILITY. THE GASKET WAS REPLACED. THE GRAHAM MFG. CO. GLAND SEAL CONDENSER, TYPE EWFTS-SWING-LOK BECAME OVERPRESSURIZED DURING UNIT START RESULTING IN GASKET FAILURE.

ACCESSION NUMBER 107505

HPCI VALVE FAILS TO OPEN AT FITZPATRICK
NIAGARA MOHAWK POWER CORP., SYRACUSE, N.Y.
3 PGS, LTR W/AO 75-79 TO NRC DIRECTORATE OF LICENSING, OCT. 20, 1975,
DOCKET 50-333, TYPE--BWR, MFG--G.E., AE--STONE & WEBSTER
CAUSE - DIRTY CONTACTS. DURING A TEST WITH THE REACTOR AT 1875 MWT, THE HPCI STEAM SUPPLY TO TURBINE VALVE FAILED TO OPEN ON SIGNAL FROM THE CONTROL ROOM. CONTACTS ASSOCIATED WITH THE LIMITORQUE MOTOR OPERATOR HAD PIECES OF IDENTIFICATION LABEL BACKING CAUGHT BETWEEN THEM. APPARENTLY HAVING FALLEN INTO POSITION AT SOMETIME WHEN THE COVER WAS REMOVED. THE PAPER WAS REMOVED AND THE VALVE OPERATED SATISFACTORY.

ACCESSION NUMBER 107976

HPCI ISOLATED DURING TESTING AT FITZPATRICK
NIAGARA MOHAWK POWER CORP., SYRACUSE, N.Y.
3 PGS, LTR W/AO 50-33/75-82 TO NRC DIRECTORATE OF LICENSING, NOV. 4,
1975, DOCKET 50-333, TYPE--BWR, MFG--G.E., AE--STONE & WEBSTER
CAUSE - INITIAL STEAM FLOW EFFECTS. DURING AUTOMATIC HPCI INITIATION ON LOW REACTOR WATER LEVEL DUE TO MSIV TESTING FOR A STARTUP, THE INITIAL STEAM FLOW FOR THE HPCI TURBINE ACTUATED THE HPCI STEAM LINE HIGH FLOW SENSORS CAUSING HPCI ISOLATION. REACTOR WATER WAS RETURNED TO NORMAL USING THE FEEDWATER PUMPS IN LESS THAN 1 MINUTE. SNUBBER PINS WERE RELOCATED TO MINIMIZE THE EFFECT OF INITIAL FLOW TO THE TURBINE.

ACCESSION NUMBER 113905

HPCI TURBINE TRIPS ON HIGH STEAM FLOW AT PEACH BOTTOM 3
PHILADELPHIA ELECTRIC CO., PA
1 PG. LER 50-278-3-76-37/1T TO U.S. NRC, MAY 14, 1976, DOCKET 50-278,
TYPE--BWR, MFG--G.E., AE--BECHTEL
CAUSE - RAPID OPENING OF TURBINE VALVE. FOLLOWING A SCRAM VESSEL LEVEL AUTOMATICALLY INITIATED HPCI OPERATION. DURING START OPERATION, HIGH STEAM FLOW IN THE HPCI SUPPLY LINE TRIPPED. HIGH STEAM FLOW WAS CAUSED BY RAPID OPENING OF THE TURBINE STOP VALVE. THE VALVE WAS REPAIRED AND THE TURBINE SUCCESSFULLY OPERATED.

ACCESSION NUMBER 114631

HPCI PUMP GLAND SEAL CONDENSER FAILS AT VERMONT YANKEE
VERMONT YANKEE NUCLEAR POWER CORP., RUTLAND, VT
3 PGS. LTR W/RO-76-12/3L TO NRC OFFICE OF I & E. REGION I. JUNE 7, 1976.
DOCKET 50-271. TYPE--BWR. MFG--G.E., AE--EBASCO
CAUSE - OVERPRESSURIZED DURING START. WHILE PERFORMING THE HPCI SYSTEM PUMP OPERABILITY TEST WITH THE REACTOR AT 98% POWER, THE HEAD GASKET ON THE GLAND SEAL CONDENSER FAILED. THE CONDENSER IS REQUIRED FOR PROPER SYSTEM OPERATION. THE GRAHAM MFG. CO. GLAND SEAL CONDENSER, SIZE 12 INCH X 6 FEET, TYPE EWFTS-SWING-LOK, BECAME OVERPRESSURIZED DURING THE PUMP START. MANUAL VALVES UPSTREAM OF THE CONDENSER AND LUBE OIL COOLER WERE FOUND TO BE 3 TO 4 TURNS OPEN. THE POSITIONS WERE PREVIOUSLY ESTABLISHED AT 1 TURN. THE VALVES WERE LOCKED IN THEIR PROPER THROTTLED POSITION.

ACCESSION NUMBER 115654

HPCI SYSTEM FAILS AT FITZPATRICK
NIAGARA MOHAWK POWER CORP., SYRACUSE, NY
2 PGS, LTR W/RO 76-30 TO NRC DIRECTORATE OF LICENSING, JULY 6, 1976, DOCKET 50-333, TYPE--BWR, MFG--G.E., AE--STONE & WEBSTER
CAUSE - GLAND SEAL CONDENSER GASKET FAILURE. DURING HPCI SUBSYSTEM LOGIC TESTING WHILE OPERATING AT 95% POWER AND UPON START OF HPCI-CST TO CST FLUSH, THE GLAND SEAL CONDENSER COOLING SIDE GASKET FAILED MAKING HPCI INOPERABLE. THE GASKET WAS REPLACED AND WILL BE WATCHED TO DETERMINE WHETHER A CHANGE IN MATERIAL OR OPERATION IS NEEDED.

ACCESSION NUMBER 117957

HPCI TURBINE FAILS TO OPERATE PROPERLY AT BROWNS FERRY 3
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA, TN
2 PGS, LTR W/BFRC-50-296/765 TO NRC OFFICE OF I & E, REGION II, SEPT. 17, 1976, DOCKET 50-296, TYPE--BWR, MFG--G.E., AE--TVA
CAUSE - GROUNDED CONNECTOR ON GOVERNOR. DURING A HPCI STARTUP TEST WITH THE REACTOR AT 8% POWER, THE TURBINE CYCLED BETWEEN ITS OVERSPEED TRIP AND THE TRIP RESET AND RESTART POINT. A WOODWARD GOVERNOR CO. EG-M BOX, PART NO. 8270-811, FAILED DUE TO A GROUNDED CONNECTOR ON THE GOVERNOR. THE CONNECTOR GROUND WAS CLEARED BY REASSEMBLY OF THE CONNECTOR AND A NEW EG-M BOX WAS INSTALLED AND CALIBRATED.

ACCESSION NUMBER 118234

HPCI TURBINE STEAM DISCHARGE LINE RUPTURE DISK RUPTURES AT BROWNS FERRY 3
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA, TN
2 PGS, LTR W/BFRC-50-296/767 TO NRC OFFICE OF I & E, REGION II, SEPT. 22, 1976, DOCKET 50-296, TYPE--BWR, MFG--G.E., AE--TVA
CAUSE - CHECK VALVE BINDING. DURING A STARTUP TEST ON THE HPCI TURBINE WITH THE REACTOR AT 3% POWER, THE RUPTURE DISK LOCATED ON THE STEAM DISCHARGE LINE RUPTURED. HIGH EXHAUST PRESSURE TURBINE TRIPS OCCURRED ON SUBSEQUENT RUNS. A SWING/CHECK AND/OR A STOP CHECK VALVE IN THE EXHAUST LINE WERE BINDING WHICH CAUSED A PRESSURE BUILDUP IN THE EXHAUST LINE. HPCI WAS RUN SATISFACTORILY AFTER REPAIRS OF THE VALVES.

ACCESSION NUMBER 118800

HPCI TRIPS AND RCIC FAILS TO OPERATE PROPERLY AT BROWNS FERRY 1
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA, TN
2 PGS, LTR W/BFRC-50-259/7615 TO NRC OFFICE OF I & E, REGION II, SEPT. 30, 1976, DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA
CAUSE - LEAKING RUPTURE DISC/SLUGGISH GOVERNOR. WITH THE REACTOR AT 1% POWER, HPCI TRIPPED DURING TESTING DUE TO A LEAKING RUPTURE DISC ON THE STEAM DISCHARGE LINE. FOLLOWING THIS, RCIC FAILED THE REQUIRED SURVEILLANCE TEST DUE TO A SLUGGISH GOVERNOR. THE REACTOR WAS PLACED IN COLD SHUTDOWN. THE HPCI RUPTURE DISC CRACKED AS A RESULT OF ALTERNATING PRESSURE AND VACUUM. A NEW RUPTURE DISC WITH A VACUUM SUPPORT WAS INSTALLED. THE DEFECTIVE WOODWARD GOVERNOR EG-R WAS REPLACED WITH A NEW ONE.

ACCESSION NUMBER 120476

HPCI TURBINE STEAM SUPPLY VALVE FAILS TO OPEN AT BROWNS FERRY 2
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA, TN
2 PGS, LTR W/BFRO-50-260/7617 TO NRC OFFICE OF I & E, REGION II, DEC. 15, 1976, DOCKET 50-260, TYPE--BWR, MFG--G.E., AE--TVA
CAUSE - TORQUE SWITCH GEAR PIN SHEARED. DURING TESTING WITH THE REACTOR AT 50% POWER, HPCI TURBINE STEAM SUPPLY VALVE 2-FCV-73-16 FAILED TO OPEN. THE BREAKER OVERLOADS WERE FOUND TRIPPED. THEY WERE RESET AND THE VALVE OPENED. THE TORQUE SWITCH GEAR ASSEMBLY PIN FOR THE LIMITORQUE SIZE SMB-2 VALVE OPERATOR SHEARED PREVENTING THE TORQUE SWITCH FROM STOPPING THE MOTOR WHEN THE VALVE CLOSED CAUSING THE OVERLOADS TO TRIP. THE PIN WAS REPLACED AND THE VALVE OPERATED SATISFACTORILY.

ACCESSION NUMBER 120684

HPCI STEAM SUPPLY VALVE FAILS TO OPEN AT BRUNSWICK 1
CAROLINA POWER & LIGHT CO., RALEIGH, NC
2 PGS, LTR W/LER 76-3 TO U.S. NRC, REGION II, DEC. 21, 1976, DOCKET 50-325, TYPE--BWR, MFG--G.E., AE--UE&C
CAUSE - VALVE MOTOR BRUSHES STICKING. WITH THE REACTOR AT 5% POWER IN STARTUP MODE, HPCI STEAM SUPPLY VALVE E41-F001 WOULD NOT OPEN DURING INITIAL TESTING. THE VALVE MOTOR WOULD NOT TURN. THE MOTOR ON THE VALVE OPERATOR WAS FOUND TO HAVE THE BRUSHES STICKING. BRUSH RIGGING WAS REWORKED, COMMUTATOR TURNED DOWN, AND BRUSHES WERE RESEATED.

ACCESSION NUMBER 122410

REACTOR SCRAMS DUE TO EQUALIZING PLANT BATTERIES AT BRUNSWICK 1
CAROLINA POWER & LIGHT CO., RALEIGH, NC
4 PGS, LTR W/LER 1-77-10 TO U.S. NRC, REGION II, FEB. 16, 1977, DOCKET 50-325, TYPE--BWR, MFG--G.E., AE--UE&C
DATE OF EVENT - 011777. POWER LEVEL - 73%. CAUSE - OVERVOLTAGE SET POINTS INCORRECT. WITH THE REACTOR AT POWER, THE PLANT EMERGENCY BATTERIES WERE SWITCHED TO EQUALIZE CHARGE WHICH RESULTED IN A REACTOR SCRAM AND POWER LOSS TO HPCI AND RCIC AUTOMATIC CONTROLS. THE OVERVOLTAGE SET POINTS OF THE CONTROL VOLTAGE POWER SUPPLIES (TOPAZ INVERTERS) WERE FOUND TO BE 140.8V AND 137.8V FOR LOOPS A AND B RESPECTIVELY. THE EQUALIZING RATE WAS 143 +/- 1V. THE CORRECT TRIP SET POINT IS 147 +/- .5 V.

ACCESSION NUMBER 123101

HPCI TURBINE FAILS TO START AT VERMONT YANKEE
VERMONT YANKEE NUCLEAR POWER CORP., RUTLAND, VT
3 PGS, LTR W/RO-77-6/3L TO NRC OFFICE OF I & E, REGION I, MARCH 11, 1977, DOCKET 50-271, TYPE--BWR, MFG--G.E., AE--EBASCO
DATE OF EVENT - 020977. POWER LEVEL - 99%. CAUSE - EXCESSIVE OIL PRESSURE IN OVERSPEED TRIP. WHILE TESTING THE HPCI SYSTEM, THE HPCI TURBINE FAILED TO START. THE TERRY STEAM TURBINE CO., MODEL CCS, TURBINE FAILED DUE TO EXCESSIVE OIL PRESSURE WITHIN THE EMERGENCY OVERSPEED TRIP MECHANISM. THIS CAUSED THE TRIP TO OSCILLATE FROM A RESET TO A TRIP CONDITION. THE BLEED OFF ORIFICE CONTROLLING THE OIL PRESSURE WAS PARTIALLY OBSTRUCTED BY SCALE BUILDUP. THE ORIFICE WAS CLEANED AND THE TURBINE WAS TESTED SATISFACTORILY.

ACCESSION NUMBER 124913

HPCI TRIPS FOLLOWING REACTOR SCRAM AT BRUNSWICK 2
CAROLINA POWER & LIGHT CO.
3 PGS, LTR W/LER 2-77-24 TO U.S. NRC, REGION II, APRIL 29, 1977, DOCKET 50-324, TYPE--BWR, MFG--G.E., AE--UE&C
DATE OF EVENT - 040577. POWER LEVEL - 0%. CAUSE - HIGH DIFFERENTIAL TEMPERATURE GRADIENT. THE REACTOR HAD JUST SCRAMMED FROM 70% POWER AT 980 PSIG WITH REACTOR LEVEL AT 37 INCHES. HPCI AUTO STARTED BUT THEN TRIPPED, APPARENTLY DUE TO HIGH DIFFERENTIAL TEMPERATURE ISOLATION SIGNAL. THE REACTOR BUILDING HEATING WAS OFF DUE TO THE AUXILIARY BOILERS BEING SECURED. A HIGH DELTA T RESULTED BETWEEN THE WARM HPCI ROOM AND THE COLD REACTOR BUILDING MAKEUP AIR. RCIC WAS USED TO MAINTAIN VESSEL LEVEL.

ACCESSION NUMBER 125316

HPCI TURBINE STEAM SUPPLY VALVE FAILS TO OPEN AT BROWNS FERRY 1
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA, TN
3 PGS, LTR W/BFRO-50-259/7715 TO NRC OFFICE OF I & E, REGION II, JUNE 6, 1977, DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA
DATE OF EVENT - 050577. POWER LEVEL - 100%. CAUSE - BROKEN TEETH ON GEARS. DURING A TEST, HIGH PRESSURE COOLANT INJECTION TURBINE STEAM SUPPLY ISOLATION VALVE FCV 1-73-16 WOULD NOT OPERATE ELECTRICALLY. THE MOTOR WAS REMOVED FROM THE VALVE ACTUATOR. TEETH WERE BROKEN ON THE MOTOR PINION GEAR AND THE CLUTCH GEAR. NO CAUSE OTHER THAN NORMAL USAGE AND WEAR WAS FOUND. THE GEARS WERE REPLACED. THIS IS A PHILADELPHIA GEAR CORP. LIMITORQUE VALVE ACTUATOR MODEL SMB-2.

ACCESSION NUMBER 126984

HPCI TURBINE STEAM SUPPLY VALVE FAILS TO OPEN AT BROWNS FERRY 2
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA, TN
3 PGS, LTR W/BFRO-50-296/7710 TO NRC OFFICE OF I & E, REGION II, JULY 25, 1977, DOCKET 50-296, TYPE--BWR, MFG--G.E., AE--TVA
DATE OF EVENT - 070577. POWER LEVEL - 60%. CAUSE - TORQUE SWITCH GEAR ASSEMBLY SHEARED. DURING A TEST, HPCI TURBINE STEAM SUPPLY VALVE 3-FCV-73-16 FAILED TO OPEN. THE BREAKER OVERLOADS WERE FOUND TRIPPED. THE TORQUE SWITCH GEAR ASSEMBLY FOR THE LIMITORQUE SIZE SMB-2 VALVE OPERATOR SHEARED PREVENTING THE TORQUE SWITCH FROM STOPPING THE MOTOR WHEN THE VALVE CLOSED. THE ASSEMBLY WAS REPLACED, OVERLOADS RESET, AND THE VALVE OPERATED SATISFACTORILY.

ACCESSION NUMBER 128537

HPCI TURBINE SPEED CONTROLLER FAILS TO CONTROL AT BROWNS FERRY 1
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA, TN
2 PGS, LTR W/BFRO-50-259/7722 TO NRC OFFICE OF I & E, REGION II, AUG. 31, 1977, DOCKET 50-259, TYPE--BWR, MFG--G.E., AE--TVA
DATE OF EVENT - 080877. POWER LEVEL - 82%. CAUSE - DROPPING RESISTOR ASSEMBLY FAILED. DURING A TEST, THE HPCI TURBINE SPEED CONTROLLER WOULD NOT CONTROL THE TURBINE AND STEAMLINE ISOLATION OCCURRED FROM HIGH STEAM FLOW. THE DROPPING RESISTOR ASSEMBLY (WOODWARD PART NO. 8270-282) WHICH SUPPLIES POWER TO THE WOODWARD GOVERNOR FAILED DUE TO AN OPENED RESISTOR. THE ASSEMBLY WAS REPLACED.

ACCESSION NUMBER 129831

HPCI VALVE FAILS TO OPEN AT DRESDEN 2
COMMONWEALTH EDISON CO., MORRIS, IL
4 PGS, LTR W/RO 50-237/1977-35 TO NRC DIRECTORATE OF REGULATORY OPERATIONS, REGION III, SEPT. 23, 1977, DOCKET 50-237, TYPE--BWR, MFG--G.E., AE--SGT & LUNDY
DATE OF EVENT - 091077. POWER LEVEL - 50%. CAUSE - SEVERAL RELATED MALFUNCTIONS. FOLLOWING A HPCI FLOW TEST, VALVE 2-2301-8 COULD NOT BE OPENED. THE BREAKER OVERLOADS WERE TRIPPING OUT AND A 170 OHM GROUND WAS MEASURED ON THE MOTOR LEADS. THE LIMIT SWITCH AND TORQUE SWITCH HOUSINGS WERE FILLED WITH WATER, THE MOTOR WINDINGS SATURATED, THE TORQUE SWITCH BROKE OFF ITS MOUNT, AND THE VALVE STEM BENT. THE WATER CAME FROM PACKING STEAM LEAKS FROM 2 NEARBY VALVES. THE VALVES HAVE BEEN REPACKED. THE MOTOR OPERATOR APPEARS TO BE OVERSIZED. A SMALLER ONE IS ON ORDER. THE TORQUE SWITCH LIMIT SWITCH, AND VALVE STEM WILL BE REPLACED DURING THE CURRENT REFUELING OUTAGE.

ACCESSION NUMBER 131213

HPCI SYSTEM INOPERABLE AND DRIFT IN ADS TIMERS AT PEACH BOTTOM 3
PHILADELPHIA ELECTRIC CO., DELTA, PA
2 PGS, LTR W/RO 3-77-46/1P TO NRC OFFICE OF I & E, REGION I, SEPT. 2, 1977, DOCKET 50-278, TYPE--BWR, MFG--G.E., AE--BECHTEL
DATE OF EVENT - 090277. POWER LEVEL - 100%. CAUSE - VALVE MALFUNCTION/SET POINT DRIFT. WHILE OPERATING AT FULL POWER PERFORMANCE OF A HPCI SURVEILLANCE TEST IDENTIFIED AN INOPERABLE TURBINE INLET STEAM SUPPLY VALVE. DURING THE REQUIRED SURVEILLANCE TESTING, THE 2 TIMERS IN THE ADS LOGIC WERE FOUND TO OPERATE AT 128.5 AND 129.5 SECONDS. THE REQUIRED TIME DELAY IS 120 +/- 5 SECONDS. THE SET POINT SHIFT WAS CAUSED BY A DEFICIENCY IN THE RELAY DESIGN FOR THIS SERVICE. SET POINTS WERE FOUND TO OPERATE PROPERLY WITH NO DIFFERENTIAL PRESSURE BUT SOMETIMES DREW HIGH MOTOR CURRENT UNDER NORMAL DIFFERENTIAL PRESSURE.

ACCESSION NUMBER 131220

HPCI FOUND INOPERABLE AT PEACH BOTTOM 3
PHILADELPHIA ELECTRIC CO., DELTA, PA
1 PG, LTR W/RO 3-77-34/1P TO NRC OFFICE OF I & E, REGION I, JULY 22, 1977, DOCKET 50-278, TYPE--BWR, MFG--G.E., AE--BECHTEL
DATE OF EVENT - 072177. POWER LEVEL - 100%. CAUSE - TURBINE CONTROL VALVE MALFUNCTION. DURING A SURVEILLANCE TEST ON THE HPCI SYSTEM, THE SPEED CONTROL ON THE TURBINE WAS FOUND TO BE VERY ERRATIC. THE CAUSE WAS A MALFUNCTION OF THE TURBINE CONTROL VALVE OPERATING MECHANISM. THE CAUSE IS UNDER INVESTIATION. AT THIS TIME, THE RCIC WAS OUT OF SERVICE BECAUSE OF A PREVIOUS FAILURE OF THE INNER ISOLATION VALVE. THE PLANT WAS IMMEDIATELY PLACED IN A COLD SHUTDOWN CONDITION. HPCI WILL BE REPAIRED PRIOR TO STARTUP.

BEST DOCUMENT AVAILABLE

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ACCESSION NUMBER 132735

HPCI TURBINE SPEED CONTROLLER FAILS TO CONTROL AT BROWNS FERRY 3
TENN. VALLEY AUTHORITY. CHATTANOOGA. TENN.
5 PGS. LTR W/BFRO-50-296/7715 TO NRC OFFICE OF I&E. REGION II. SEPT. 16. 1977. DOCKET 50-296. TYPE--BWR. MFG--G.E.. AE--TVA
DATE OF EVENT - 083077. POWER LEVEL - 87%. CAUSE - RESISTOR OPENED. DURING TESTING, HPCI TURBINE SPEED CONTROLLER WOULD NOT CONTROL THE TURBINE. THE DROPPING RESISTOR ASSEMBLY (WOODWARD PART NO. 8270-282) WHICH SUPPLIES POWER TO THE WOODWARD GOVERNOR FAILED DUE TO AN OPENED RESISTOR. REPAIRS WERE COMPLETED PRIOR TO COMPLETING ALL BACKUP TESTING.

ACCESSION NUMBER 133035

HPCI TURBINE GOVERNOR STICKS AT HATCH 1
GEORGIA POWER CO., BAXLEY, GA
3 PGS. LTR W/RO 50-321/1977-90 TO NRC OFFICE OF I & E. REGION II. DEC. 20. 1977. DOCKET 50-321. TYPE--BWR. MFG--G.E.. AE--SSI
DATE OF EVENT - 120477. POWER LEVEL - 0%. CAUSE - DAMAGED ELECTRICAL CONNECTOR. WHILE PERFORMING HPCI PUMP RATED FLOW TEST DURING HOT STANDBY WITH THE REACTOR AT 10 MW, IT WAS FOUND THAT THE HPCI TURBINE GOVERNOR WAS STUCK AND WOULD NOT RESPOND TO CONTROL. THE REACTOR WAS TAKEN TO COLD SHUTDOWN. THE TURBINE GOVERNOR ACTUATOR WAS FOUND TO HAVE A DAMAGED ELECTRICAL CONNECTION ON A LINE OF FLEXIBLE CONDUIT RUNNING TO IT FROM THE CONTROL BOX. REPAIRS WERE MADE. THE ACTUATOR IS A WOODWARD GOVERNOR CO. MANUFACTURE. TYPE EG-R-20. PART NO. 8250-133.

ACCESSION NUMBER 135274

HPCI SYSTEM BECOMES INOPERABLE AT BRUNSWICK 2
CAROLINA POWER & LIGHT CO.. RALEIGH. NC
3 PGS. LTR W/LER 2-77-64 TO U.S. NRC. REGION II. OCT. 4. 1977. DOCKET 50-324. TYPE--BWR. MFG--G.E.. AE--UE&C
DATE OF EVENT - 090477. POWER LEVEL - 0%. CAUSE - OIL LEAK IN CONTROL OIL SYSTEM. A REACTOR SCRAM WAS RECEIVED FOLLOWING A GENERATOR LOCKOUT CAUSED BY A LOSS OF EXCITATION TO THE GENERATOR. WHEN REACTOR WATER LEVEL REACHED -38 INCHES, GROUP I ISOLATION OCCURRED AND BOTH HPCI AND RCIC STARTED. A LEAKING OIL LINE ON THE HPCI CONTROL OIL SYSTEM PREVENTED HPCI FROM PERFORMING PROPERLY. THERE WAS A LOOSE FITTING IN THE CONTROL OIL LINE TO THE SERVO MECHANISM (FOR THE STEAM THROTTLE VALVE) WHICH WAS PROBABLY CAUSED BY A SLIGHT VIBRATION OVER A PERIOD OF TIME. THE FITTING WAS CLEANED AND REASSEMBLED USING A SEALING COMPOUND.

ACCESSION NUMBER 135279

HPCI FLOW CONTROLLER FOUND TO BE DEFECTIVE AT PEACH BOTTOM 3
PHILADELPHIA ELECTRIC CO., PHILADELPHIA, PA
2 PGS. LTR W/LER 77-044/03L-0 TO NRC OFFICE OF I & E. REGION I. DEC. 12. 1977. DOCKET 50-278. TYPE--BWR. MFG--G.E.. AE--BECHTEL
DATE OF EVENT - 093077. POWER LEVEL - 2%. CAUSE - DEFECTIVE CIRCUIT BOARD MODULE. WHILE PERFORMING A SURVEILLANCE TEST WITH THE REACTOR IN STARTUP MODE, HPCI FLOW CONTROLLER FC-3-23-108 WAS FOUND TO BE DEFECTIVE PREVENTING HPCI FROM OBTAINING A FLOW OF 5000 GPM AS REQUIRED. THE GE MODEL 540017HAPV2 FLOW CONTROLLER HAD A FAILED CIRCUIT BOARD MODULE. THE CONTROLLER WAS IMMEDIATELY REPLACED IN KIND AND THE TEST PERFORMED SUCCESSFULLY.

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ACCESSION NUMBER 136399

HPCI TURBINE STOP VALVE FAILS TO OPEN AT PILGRIM 1
BOSTON EDISON CO., PLYMOUTH, MA
2 PGS, LTR W/LER 78-008/03L-0 TO NRC OFFICE OF I & E, REGION I, MARCH 17, 1978, DOCKET 50-293, TYPE--BWR, MFG--GE, AE--BECHTEL
DATE OF EVENT - 030578. POWER LEVEL - 0%. CAUSE - OIL FILTER PLUGGED. THE REACTOR SCRAMMED DUE TO REACTOR HIGH PRESSURE. REACTOR WATER LEVEL WENT HIGH RESULTING IN AN MSIV ISOLATION. AFTER THE HIGH WATER LEVEL ISOLATION SIGNAL CLEARED, AN ATTEMPT WAS MADE TO PLACE THE HPCI IN FULL FLOW TEST AS AN ALTERNATE HEAT SINK. THE TURBINE STOP VALVE FAILED TO OPEN. INVESTIGATION REVEALED THAT THE NUGENT DUPLEX OIL FILTER IN SERVICE WS DIRTY. THIS REDUCED OIL PRESSURE TO THE OIL PISTON OPERATED RELAY VALVE OF THE TURBINE STOP VALVE WHICH PREVENTED IT FROM BEING CORRECTLY POSITIONED. THE FILTER WILL BE INCLUDED IN THE PREVENTIVE MAINTENANCE PROGRAM.

ACCESSION NUMBER 136401

WATER FOUND BLOWING FROM AROUND HPCI PUMP CASE FLANGE AT COOPER
NEBRASKA PUBLIC POWER DISTRICT, BROWNVILLE, NE
3 PGS, LTR W/RO 50-298-78-3 TO NRC OFFICE OF I & E, REGION IV, FEB. 1, 1978, DOCKET 50-298, TYPE--BWR, MFG--GE, AE--BURNS & ROE
DATE OF EVENT - 011178. POWER LEVEL - 73%. CAUSE - MALFUNCTION OF TURBINE SPEED CONTROL. DURING A HPCI PUMP OPERABILITY TEST, A SIGNIFICANT AMOUNT OF WATER WAS DISCOVERED BLOWING FROM AROUND THE PUMP CASE FLANGE. AN ELECTRO 722543 MAGNETIC PICKUP FAILED ALLOWING THE HPCI TURBINE CONTROL TO RAPIDLY INCREASE PUMP SPEED RESULTING IN A RAPID PRESSURE TRANSIENT IN THE PUMP CASE CAUSING A GASKET FAILURE. PUMP CASE BOLTING HAD NOT BEEN TORQUED CORRECTLY DURING A PREVIOUS ASSEMBLY. THE GASKET AND PICKUP WERE REPLACED AND THE BOLTS TORQUED CORRECTLY.

ACCESSION NUMBER 137250

HPCI SYSTEM ISOLATES DUE TO HIGH AMBIENT TEMPERATURE AT DRESDEN 2
COMMONWEALTH EDISON CO., MORRIS, IL
3 PGS, LTR W/RO 78-023/01T-0 TO NRC DIRECTORATE OF REGULATORY OPERATIONS, REGION III, APRIL 3, 1978, DOCKET 50-237, TYPE--BWR, MFG--GE, AE--SGT & LUNDY
DATE OF EVENT - 032078. POWER LEVEL - 96%. CAUSE - LEAK AROUND CONTROL VALVE STEAM CHEST. DURING SURVEILLANCE, THE HPCI SYSTEM ISOLATED DUE TO HIGH AMBIENT TEMPERATURE. A LEAK WAS IDENTIFIED AROUND THE CONTROL VALVE STEAM CHEST. THE UNDERLYING CAUSE COULD NOT BE DETERMINED. CORRECTIVE ACTION WAS TO STONE BOTH MATING SURFACES OF THE STEAM CHEST, APPLY A DIFFERENT TYPE OF SEALER, AND USE PIECE OF TEFLON STRING AROUND THE STUDS.

BEST DOCUMENT AVAILABLE 112

ACCESSION NUMBER 137883

HPCI EXHAUST LINE RUPTURE DISC RUPTURES AT PILGRIM 1
BOSTON EDISON CO., PLYMOUTH, MA
2 PGS, LTR W/LER 78-013/03L-0 TO NRC OFFICE OF I & E, REGION I, APRIL 28, 1978, DOCKET 50-293, TYPE--BWR, MFG--GE, AE--BECHTEL
DATE OF EVENT - 040878. POWER LEVEL - 0%. CAUSE - NO APPARENT CAUSE. DURING A HPCI PUMP OPERABILITY AND FLOW RATE AT 1000 PSIG TEST, ANNUNCIATION WAS RECEIVED ON THE STEAM LEAK DETECTION SYSTEM FOR HPCI TORUS AREA HIGH TEMP. THE HPCI WAS SECURED IMMEDIATELY AND AN INVESTIGATION CONDUCTED WHICH REVEALED THAT THE EXHAUST LINE RUPTURE DISC HAD RUPTURED. NO APPARENT CAUSE FOR THE RUPTURING OF THE DIAPHRAGM COULD BE FOUND, HOWEVER, ATMOSPHERIC PRESSURE CHANGES IN THE EXHAUST LINE HAVE BEEN FOUND TO ACCELERATE THE WORK HARDENING PROCESS BY FLEXING THE DIAPHRAGM, CONTRIBUTING TO FAILURE. BACKING PLATES MINIMIZE THIS PROCESS, THEREFORE A PDCR WILL BE ISSUED TO INSTALL THESE PLATES ON THE HPCI EXHAUST LINE.

ACCESSION NUMBER 137930

HPCI SPEED CONTROL FAILS TO MAINTAIN CONSTANT SPEED AT BRUNSWICK 2
CAROLINA POWER & LIGHT CO., RALEIGH, NC
2 PGS, LTR W/LER 2-78-039 TO U.S. NRC, REGION II, MAY 12, 1978, DOCKET 50-324, TYPE--BWR, MFG--GE, AE--UE&C
DATE OF EVENT - 041278. POWER LEVEL - 93%. CAUSE - DEFECTIVE HYDRAULIC ACTUATOR UNIT. DURING A HPCI 1000 LB. FLOW RATE TEST, A CONTROL OPERATOR DISCOVERED THE HPCI SPEED CONTROL WOULD NOT MAINTAIN A CONSTANT R.P.M. THE EGR (HYDRAULIC ACTUATOR), WHICH IS USED TO CONTROL HPCI TURBINE SPEED WAS DEFECTIVE. THE EGR HYDRAULIC UNIT WAS SENT TO THE VENDOR FOR REPAIR. THE VENDORS REPAIR REPORT WILL BE USED TO DETERMINE IF ANY FURTHER CORRECTIVE ACTION IS REQUIRED TO PREVENT RECURRENCES.

ACCESSION NUMBER 139845

HPCIS HIGH PRESSURE PUMP DAMAGED DURING A TEST AT BROWNS FERRY 2
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA, TN
2 PGS, LTR W/BRO-50-260-7814 TO NRC OFFICE OF I & E, REGION II, JULY 18, 1978, DOCKET 50-260, TYPE--BWR, MFG--GE, AE--TVA
DATE OF EVENT - 062778. POWER LEVEL - 5%. CAUSE - OPERATOR FAILED TO RECOGNIZE LOW OIL PRESSURE. DURING SURVEILLANCE TESTING, THE HPCIS SUSTAINED DAMAGE TO THE HIGH-PRESSURE PUMP AND THE REDUCTION GEAR SET WHICH DRIVES THE LOW PRESSURE PUMP. OPERATIONS PERSONNEL FAILED TO RECOGNIZE INSUFFICIENT OIL PRESSURE AND TO OPEN A VALVE IN THE LUBRICATION OIL LINE WHICH SUPPLIES OIL TO THE BYRON-JACKSON DVMX PUMP AND REDUCTION GEAR. AS A RESULT, THE PARTS OVERHEATED. A DESIGN CHANGE TO PROVIDE A LOW OIL PRESSURE ALARM AND A PROCEDURE CHANGE TO VERIFY VALVE ALIGNMENT WILL BE INITIATED.

ACCESSION NUMBER 139894

HPCI PUMP TRIPS DUE TO LOSS OF VOLTAGE TO THE GOVERNOR AT BROWNS FERRY 3
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA, TN
2 PGS, LTR W/BFRO-50-296/7816 TO NRC OFFICE OF I & E, REGION II, JULY 24, 1978, DOCKET 50-296, TYPE--BWR, MFG--GE, AE--TVA
DATE OF EVENT - 070678. POWER LEVEL - 95%. CAUSE - RESISTOR FAILURE. DURING NORMAL OPERATION WHILE PERFORMING SURVEILLANCE TESTING, THE HPCI PUMP TRIPPED DUE TO A LOSS OF VOLTAGE TO THE GOVERNOR. A PACIFIC RESISTOR CO. 250 OHM 75 WATT 3% RESISTOR, 100 CH, HAD OPENED WHICH CAUSED THE HPCI GOVERNOR TO BE INOPERATIVE. THE RESISTOR WAS REPLACED. A DESIGN CHANGE HAS BEEN APPROVED TO INCREASE THE WATTAGE RATING OF THE RESISTOR. THE CHANGE WILL BE MADE AT THE REFUELING OUTAGE.

ACCESSION NUMBER 140195

MOTOR-DRIVEN FIRE PUMP INOPERABLE AT NORTH ANNA 1
VIRGINIA ELECTRIC & POWER CO., RICHMOND, VA
3 PGS, LTR W/LER 78-048/03L-0 TO NRC OFFICE OF I & E, REGION II, JULY 17, 1978, DOCKET 50-338, TYPE--PWR, MFG--WEST., AE--STONE & WEBSTER
DATE OF EVENT - 060878. POWER LEVEL - 92%. CAUSE - CONTROL CIRCUIT OF BREAKER FAILED TO DEENERGIZE. MOTOR-DRIVEN FIRE PUMP 1-FP-P-1 BECAME INOPERABLE ON JUNE 8, 1978 DUE TO STARTER PROBLEMS. BECAUSE OF SPARE PART PROCUREMENT PROBLEMS, 1-FP-P-1 REMAINED INOPERABLE FOR 12 DAYS 3 HOURS 30 MINUTES. THE CONTROL CIRCUIT OF THE MOTOR-DRIVEN FIRE PUMP 1-FP-P-1 BREAKER FAILED TO DEENERGIZE AFTER CLOSING THE THREE PHASE CONTACTS OF THE FIRE PUMP MOTOR CAUSING THE CONTROL CIRCUITRY TO OVERLOAD. DEFECTIVE CONTROL CIRCUIT PARTS WERE REPLACED, THE BREAKER TESTED, AND 1-FP-P-1 WAS RETURNED TO OPERABLE STATUS.

ACCESSION NUMBER 140766

HPCI AUXILIARY OIL PUMP FAILS TO START AT PEACH BOTTOM 2
PHILADELPHIS ELECTRIC CO., PHILADELPHIA, PA
2 PGS, LTR W/LER 78-036/03L-0 TO NRC OFFICE OF I & E, REGION I, SEPT. 26, 1978, DOCKET 50-277, TYPE--BWR, MFG--GE, AE--BECHTEL
DATE OF EVENT - 090178. POWER LEVEL - 90%. CAUSE - GROUND IN MOTOR. WHILE AT POWER, DURING ROUTINE SURVEILLANCE TESTING OF THE HPCI SYSTEM THE AUXILIARY OIL PUMP FAILED TO START. TESTING OF THE OTHER ECCS SYSTEMS WAS PERFORMED AS REQUIRED BY TECH SPEC. THIS TESTING DETERMINED THAT THE ADS TIMERS WERE NOT WITHIN TECH SPEC LIMITS, WHICH IS DISCUSSED IN LER 02-78-037/03L-0. THE FAILURE OF THE PUMP TO START WAS CAUSED BY A GROUND IN THE MOTOR. THE MOTOR, BALDOR TYPE 1040D, 7 1/2 H.P., 250 V.D.C. WAS REPLACED AND THE HPCI SYSTEM TESTED SATISFACTORILY WITHIN 36 HOURS.

ACCESSION NUMBER 141245

HPCI TRIPS ON OVERSPEED AT PEACH BOTTOM 3
PHILADELPHIA ELECTRIC CO., PHILADELPHIA, PA
3 PGS, LTR W/LER 78-21/1T TO NRC OFFICE OF I & E, REGION I, NOV. 20, 1978, DOCKET 50-278, TYPE--BWR, MFG--GE, AE--BECHTEL
DATE OF EVENT - 110678. POWER LEVEL - 0%. CAUSE - GOVERNOR OUT OF CALIBRATION. WHILE AT POWER, A FEEDWATER CONTROL SYSTEM FAILURE RESULTED IN A REACTOR LOW LEVEL TRANSIENT AND SCRAM. HPCI INITIATED BUT DELIVERED UNSTABLE FLOW. WITHIN MINUTES HPCI TRIPPED, APPARENTLY ON OVERSPEED. ATTEMPTS TO MANUALLY RESTART HPCI WERE UNSUCCESSFUL UNTIL ITS AUXILIARY OIL PUMP WAS REMOVED FROM SERVICE AND RESTARTED. RATED HPCI FLOW WAS ATTAINED. THE HPCI GOVERNOR (WOODWARD MODEL 8271-083) OUT OF CALIBRATION RESULTING IN UNSTABLE FLOW AND OVERSPEED TRIP. A DEFECTIVE VALVE WAS FOUND IN THE OVERSPEED TRIP RESET CIRCUIT. THE GOVERNOR WAS CALIBRATED AND OPERABILITY VERIFIED. THE VALVE WAS REPAIRED AND THE AUTO RESET CIRCUIT TESTED SATISFACTORILY.

ACCESSION NUMBER 141395

HPCI VALVE FAILS TO OPERATE AT HATCH 2
GEORGIA POWER CO., BAXLEY, GA
2 PGS, LTR W/RO 50-366/1978-56 TO NRC OFFICE OF I & E, REGION II, NOV. 3, 1978, DOCKET 50-366, TYPE--BWR, MFG--GE, AE--SSI & BECHTEL
DATE OF EVENT - 102778. POWER LEVEL - 9%. CAUSE - MOTOR INSULATION FAILURE. DURING TESTING 2E41-F001 VALVE FAILED TO OPERATE DURING THE HPCI QUICK START. THE 2E41-F001 VALVE FAILED DUE TO A MOTOR SHUNT FILED INSULATION FAILURE. THE MOTOR FAILURE WAS PROBABLY CAUSED BY FREQUENT OPERATIONS RESULTING IN A DEGRADATION OF THE INSULATION BY HEAT. THE VALVE STEM WAS ALSO FOUND ROUGH ENOUGH TO IMPAIR OPERATION BUT NOT ENOUGH TO PREVENT OPERATION. THE MOTOR WAS REWOUND AND THE STEM REPLACED. THE VALVE WAS THEN TESTED.

ACCESSION NUMBER 142591

HPCI FAILS TO OPERATE DURING TESTING AT COOPER
NEBRASKA PUBLIC POWER DISTRICT, BROWNVILLE, NE
3 PGS, LTR W/RO 50-298-78-8 TO NRC OFFICE OF I & E, REGION IV, MARCH 8, 1978, DOCKET 50-298, TYPE--BWR, MFG--GE, AE--BURNS & ROE
DATE OF EVENT - 020778. POWER LEVEL - 72%. CAUSE - TWO DELTA P INSTRUMENTS READING HIGH. DURING THE HPCI PUMP OPERABILITY TEST, TURBINE SPEED INCREASED TO GREATER THAN 4000 RPM AND A HPCI HIGH STEAM LINE DELTA P ISOLATION OCCURRED. HPCI WAS DECLARED INOPERABLE. HPCI DPIS 76 AND 77 WERE FOUND TO BE READING HIGH. THE SENSING LINES WERE NOT BACKFILLED PROPERLY AND THE SWITCHES WERE ISOLATING THE HPCI AT LESS THAN 100% FLOW. THE SENSING LINES WERE BACKFILLED AND THE INSTRUMENT READING IS NOW TAKEN DAILY.

ACCESSION NUMBER 143439

AUXILIARY HPCI OIL PUMP TRIPS TRIPPING HPCI TURBINE AT BRUNSWICK 1
CAROLINA POWER & LIGHT CO., RALEIGH, NC
7 PGS, LTR W/LER 1-77-95 TO U.S. NRC, REGION II, DEC. 2, 1977, DOCKET 50-325, TYPE--BWR, MFG--GE, AE--UE&C
DATE OF EVENT - 110577. POWER LEVEL - 100%. CAUSE - HIGH WATER IN HPCI ROOM SHORTED MOTOR. WITH THE REACTOR AT POWER WHILE TEST RUNNING THE HPCI TURBINE, THE AUXILIARY HPCI OIL PUMP TRIPPED CAUSING THE HPCI TURBINE TO TRIP. THE MOTOR FOR THE HPCI AUXILIARY OIL PUMP SHORTED OUT DUE TO A HIGH WATER LEVEL IN THE HPCI ROOM. WATER WAS BEING PUMPED TO THE HPCI ROOM FROM THE SOUTH CORE SPRAY AND SOUTH R.H.R. ROOM SUMPS FOR TRANSFER TO RADWASTE.

ACCESSION NUMBER 146498

HPCI TURBINE FAILS TO START AT DRESDEN 2
COMMONWEALTH EDISON CO.
LTR W/LER 79-002 TO U.S. NRC, REGION 3, JAN 17, 1979, DOCKET 50-237, TYPE--BWR, MFG--GE,AE--S&L CONTROL--023340
DATE OF EVENT - 010379. POWER LEVEL - 095%. CAUSE - INTERLOCK VALVE LEVER OUT OF ADJUSTMENT. HPCI TURBINE FAILED TO START DURING QUARTERLY FLOW TEST. HPCI DECLARED INOPERABLE AND REQUIRED ECCS SURVEILLANCES (T.S. 3.5.C.2) COMMENCED. DURING LATER TESTING, HPCI OPERATED SUCCESSFULLY SIX CONSECUTIVE TIMES. HPCI THEN DECLARED OPERABLE. REQUIRED SURVEILLANCE EXCEPT AUTO BLOWDOWN WERE COMPLETED SATISFACTORILY. THIS IS THE FIRST OCCURRENCE OF THIS TYPE. DURING OPERATION OF THE HPCI TURBINE ON 1/4/79 THE GENERAL ELECTRIC TECHNICAL REPRESENTATIVE NOTED A MISAJUSTMENT OF THE INTERLOCK DUMP VALVE OPERATING LEVER. THE LEVER WAS ADJUSTED.

ACCESSION NUMBER 146530

HPCI PUMP TRIPS ON LOW OIL LEVEL AT PILGRIM 1
BOSTON EDISON CO.
LTR W/LER 78-057 TO U.S. NRC, REGION 1, JAN 22, 1979, DOCKET 50-293, TYPE--BWR, MFG--GE,AE--BECH CONTROL--023395
DATE OF EVENT - 123078. POWER LEVEL - 100%. CAUSE - OIL PRESSURE GAGE FITTING DISCONNECTED. WHILE OPERATING IN FULL FLOW TEST TO STIR UP THE CONDENSATE STORAGE TANKS' SEDIMENT, THE HPCI TRIPPED. IMMEDIATE INVESTIGATION REVEALED A LOW LEVEL IN THE OIL SUMP AND THE OVERFLOW PIT AROUND THE TURBINE FILLED WITH OIL. THE HPCI WAS DECLARED INOP AND OPERABILITY OF BACKUP SYSTEMS WAS DEMONSTRATED IMMEDIATELY AS REQUIRED BY T.S. 4.5.C.2. PUBLIC HEALTH AND SAFETY WERE NOT AFFECTED. MAINTENANCE PERSONNEL DISCOVERED THE FITTING FOR THE DISCHARGE PRESSURE GAGE ON THE ATTACHED OIL PUMP WAS DISCONNECTED. THE FITTING WAS RECONNECTED.

BEST DOCUMENT AVAILABLE 116

ACCESSION NUMBER 146649

HPCI STEAM SUPPLY VALVE FAILS TO OPEN AT BROWNS FERRY 2
TENNESSEE VALLEY AUTHORITY
LTR W/LER 79-001 TO U.S. NRC, REGION 2, FEB 08, 1979, DOCKET 50-260.
TYPE--BWR,MFG--GE,AE--TVA CONTROL--025015

DATE OF EVENT - 011379. POWER LEVEL - 097%. CAUSE - OPERATOR LIMIT SWITCH FAILURE. DURING NORMAL POWER OPERATION, WHILE TESTING THE HPCI AUXILIARY OIL PUMP, STEAM SUPPLY VALVE FCV-73-16 FAILED TO OPEN, RENDERING THE HPCI SYSTEM INOPERABLE. MECHANICAL FAILURE OF THE ASSOCIATED LIMITORQUE (SMB-2) VALVE OPERATOR LIMIT SWITCH CAUSED THE MALFUNCTION. THE LIMIT SWITCH WAS REPLACED; MAINTENANCE WAS CONDUCTED ON THE HPCI AUXILIARY OIL PUMP AND RUPTURE DISC ASSEMBLY; AND THE SYSTEM WAS TESTED AND RETURNED TO NORMAL OPERATION.

ACCESSION NUMBER 146653

HPCI VALVE MOTOR BURNED DURING VALVE OPENING AT HATCH 1
GEORGIA POWER CO.
LTR W/LER 79-004 TO U.S. NRC, REGION 2, JAN 31, 1979, DOCKET 50-321.
TYPE--BWR,MFG--GE,AE--SSI/BECH CONTROL--025019

DATE OF EVENT - 011979. POWER LEVEL - 98%. CAUSE - MOTOR INTERNAL DISORDER. WHILE PERFORMING PROCEDURE HNP-1-3302 (HPCI M.O.V. OPERABILITY), THE ARMATURE WINDING OF THE HPCI INJECTION VALVE MOTOR (E41-F006) BURNED WHEN THE VALVE WAS OPENING. THE HPCI SYSTEM WAS DECLARED INOPERATIVE. THE MOST PROBABLE CAUSE WOULD BE AN INTERNAL DISORDER OF A MINOR NATURE HAVING OCCURRED IN THE MOTOR CAUSING IT TO OVERHEAT. THE BURNED AND BLACKENED CONDITION OF THE MOTOR INTERNALS OBSCURED ANY EVIDENCE OF THE ACTUAL CAUSE. VALVE WAS CHECKED FOR RESTRICTIONS IN MECHANICAL OPERATION AND THE CONTROL LOGIC MOTOR REINSTALLED AFTER IT WAS REPAIRED.

ACCESSION NUMBER 147272

HPCI TURBINE TRIPS AT PILGRIM 1
BOSTON EDISON CO.
LTR W/LER 79-008 TO U.S. NRC, REGION 1, FEB 23, 1979, DOCKET 50-293.
TYPE--BWR, MFG--GE, AE--BECH CONTROL--025165

DATE OF EVENT - 021479. POWER LEVEL - 100%. CAUSE - GLAND SEAL CONDENSER SEAL RUPTURE. WHILE PERFORMING SURVEILLANCE TEST 8.5.4.1 (HPCI PUMP OPERABILITY AND FLOW RATE TEST @ 1000 PSIG) THE HPCI TURBINE TRIPPED. IMMEDIATE INVESTIGATION REVEALED THAT THE LOWER HEAD GASKET ON THE GLAND SEAL CONDENSER HAD RUPTURED. THE CAUSE OF THE GASKET RUPTURING WAS NOT READILY DETERMINED HOWEVER, A DRIFT OF THE PRESSURE CONTROL VALVE SETPOINT IS SUSPECTED. OPERATIONS PERSONNEL HAVE BEEN INSTRUCTED TO OBSERVE THE CONTROLLER SETPOINT WHENEVER THE HPCI IS RUN. REPAIRS WERE COMPLETED, TEST 8.5.4.1 SUCCESSFULLY PERFORMED AND THE HPCI RETURNED TO SERVICE.

ACCESSION NUMBER 148210

HPCI PUMP FLOW VARIATIONS AT HATCH 1
GEORGIA POWER CO.
LTR W/LER 79-017 TO U.S. NRC, REGION 2, MAR 26, 1979, DOCKET 50-321,
TYPE--BWR, MFG--GE, AE--SSI/BECH CONTROL--025369

DATE OF EVENT - 022779. POWER LEVEL - 058%. CAUSE - TURBINE CONTROL FAILURE. DURING STEADY STATE OPERATION WHILE ATTEMPTING TO PERFORM HNP-1-3303, HPCI PUMP RATED FLOW, THE PROCEDURE HAD TO BE DISCONTINUED DUE TO VARIATIONS IN THE SPEED OF THE HPCI TURBINE. THE ADS, RCIC, RHR SYSTEMS, LPCI MODE, AND CORE SPRAY SYSTEMS WERE IMMEDIATELY DEMONSTRATED TO BE OPERABLE. THE CAUSE WAS ATTRIBUTED TO TURBINE CONTROL LOOP FAILURE. THE CONTROLS WERE CALIBRATED AND THE ACTUATOR WAS DETERMINED TO BE INOPERABLE. AFTER THE ACTUATOR WAS REPLACED THE HPCI RATED FLOW PROCEDURE AND HPCI QUICK START TEST WERE SUCCESSFULLY COMPLETED.

ACCESSION NUMBER 148218

LARGE OSCILLATION FOUND IN HPCI TURBINE SPEED AT BRUNSWICK 2
CAROLINA POWER & LIGHT CO.
LTR W/LER 79-008 TO U.S. NRC, REGION 2, MAR 29, 1979, DOCKET 50-324,
TYPE--BWR, MFG--GE, AE--UEC CONTROL--025377

DATE OF EVENT - 030179. POWER LEVEL - 078%. CAUSE - DESIGN ERROR. WHILE PERFORMING P.T. 45.3.4, HPCI INITIATION RESPONSE TEST, A LARGE OSCILLATION IN TURBINE SPEED WAS EXPERIENCED AFTER THE INITIAL ACCELERATION RAMP WAS COMPLETED. THESE OSCILLATIONS CAUSED PRESSURE VALUES TO OSCILLATE OUTSIDE ACCEPTABLE LIMITS. SET SCREWS WHICH HOLD SPUR GEAR USED FOR SPEED REFERENCE IN GOVERNOR WERE LOOSE. SET SCREWS WERE REPLACED, & LOC-TITE COMPOUND WAS ADDED. P.T. 45.3.4 WAS COMPLETED SATISFACTORILY. SET SCREWS HAVE A HISTORY OF VIBRATING LOOSE. G.E. INSTRUCTION. RECOMMENDS SELF LOCKING SCREWS. CHANGE DURING REFUELING.

ACCESSION NUMBER 148738

HPCI CONTROL VALVE FAILS TO OPERATE AT HATCH 2
GEORGIA POWER CO., BAXLEY, GA
2 PGS, LTR W/RO 50-366/1978-64 TO NRC OFFICE OF I & E, REGION II, NOV. 17, 1978, DOCKET 50-366, TYPE--BWR, MFG--GE, AE--SSI & BECHTEL

DATE OF EVENT - 110678. POWER LEVEL - 48%. CAUSE - WIRE LEFT LOOSE DURING MAINTENANCE. WITH THE REACTOR IN THE RUN MODE, WHILE ATTEMPTING TO PERFORM A HPCI QUICK START, THE HPCI CONTROL VALVES FAILED TO OPERATE. THE FAILURE OF THE HPCI QUICK START WAS DUE TO PERSONNEL ERROR. A WIRE HAD BEEN LEFT LOOSE IN THE SPEED FEEDBACK SIGNAL CIRCUIT WHEN PERSONNEL WERE PERFORMING MAINTENANCE REEQUEST 2-78-4376. THE WIRE WAS SECURED AND THE HPCI QUICK START COMPLETED SATISFACTORILY.

ACCESSION NUMBER 148739

HPCI TURBINE CONTROL VALVE FAILS TO OPERATE AT BRUNSWICK 1
CAROLINA POWER & LIGHT CO., RALEIGH, NC
4 PGS, LTR W/LER 1-78-039 TO U.S. NRC, REGION II, MAY 12, 1978, DOCKET 50-325, TYPE--BWR, MFG--GE, AE--UE&C

DATE OF EVENT - 04/12/78. POWER LEVEL - 94%. CAUSE - CORROSION IN EG-R ACTUATOR. HPCI TURBINE CONTROL VALVE V9 WOULD NOT OPERATE DURING PERFORMANCE OF QUARTERLY SURVEILLANCE TEST DUE TO EXCESSIVE CORROSION INSIDE THE ELECTRO/MECHANICAL/HYDRAULIC (EG-R) ACTUATOR. THE PILOT VALVE PLUNGER WOULD NOT OPERATE ON SIGNAL. THIS, IN TURN, PREVENTED THE CONTROL VALVE FROM MOVING. A NEW EG-R ACTUATOR (MANUFACTURED BY THE WOODWARD GOVERNOR COMPANY) WAS INSTALLED. THE TURBINE WAS RESTARTED. THE TURBINE WENT INTO AN OVERSPEED CONDITION. THE MECHANICAL OVERSPEED TRIP DEVICE FAILED TO SHUT DOWN THE MACHINE AT THE 5000 RPM SET POINT. STEAMLINE VALVES WERE CLOSED, AND THE OVERSPEED TERMINATED. TURBINE TRIP SOLENOID WAS BURNED OUT. TWO BLOWN IC CHIPS WERE FOUND IN THE SIGNAL CONVERTER SECTION OF THE CONTROLLER. A BROKEN TRIP BALL WAS FOUND IN THE MECHANICAL OVERSPEED MECHANISM.

ACCESSION NUMBER 149961

HPCI FAILS TO START WHEN TURBINE STOP VALVE FAILS TO OPEN AT HATCH 2
GEORGIA POWER CO.
LTR W/LER 79-045 TO U.S. NRC, REGION 2, JUN 11, 1979, DOCKET 50-366, TYPE--BWR, MFG--GE, AE--SSI/BECH CONTROL--026030

DATE OF EVENT - 060379. POWER LEVEL - 000%. CAUSE - WATER CONTAMINATION IN OIL. FOLLOWING A REACTOR SCRAM AT 1850 CDT, THE HPCI SYSTEM RECEIVED AN INITIATION SIGNAL BUT FAILED TO START WHEN THE TURBINE STOP VALVE DID NOT OPEN. THE REACTOR WAS BROUGHT TO A HOT SHUTDOWN CONDITION. THE RCIC SYSTEM WAS ALSO INOPERABLE. A SEAL WATER LINE, ON THE HPCI PUMP, WAS LEAKING WATER TO THE BRACKET DRAIN CAVITY WHILE OVERFLOWED INTO THE ADJACENT BEARING HOUSING CAUSING WATER CONTAMINATION TO THE OIL SYSTEM. THIS PREVENTED THE OIL OPERATED STOP VALVE FROM OPENING. THE SEAL WATER LINE WAS REPAIRED AND THE OIL REPLACED. THE STOP VALVE WAS THEN CYCLED OPEN SATISFACTORILY.

ACCESSION NUMBER 150114

HPCI VACUUM TANK CONDENSATE PUMP TRIPS AT HATCH 2
GEORGIA POWER CO.
LTR W/LER 79-049 TO U.S. NRC, REGION 2, JUN 21, 1979, DOCKET 50-366, TYPE--BWR, MFG--GE, AE--SSI/BECH CONTROL--026149

DATE OF EVENT - 060879. POWER LEVEL - 001%. CAUSE - BURNED COIL IN MOTOR. WITH THE REACTOR IN THE STARTUP AND HOT STANDBY MODE, WHILE PERFORMING HNP-2-3303 (HPCI PUMP OPERABILITY), THE HPCI VACUUM TANK CONDENSATE PUMP (2E41-C002-1) TRIPPED AFTER WHICH THE VACUUM PUMP (2E41-C002-2) ALSO TRIPPED. THE HPCI SYSTEM WAS DECLARED INOPERABLE. THE 2E41-C002-1 CONDENSATE PUMP TRIP WAS DUE TO A BURNED COIL IN THE SHUNT FIELD OF THE MOTOR. THE CONDENSATE PUMP, BEING TRIPPED, ALLOWED THE VACUUM TANK TO FILL WITH WATER AND OVERLOAD THE VACUUM PUMP, WHICH ALSO TRIPPED. THE CONDENSATE MOTOR COIL WAS REPLACED.

ACCESSION NUMBER 150269

HPCI TRIPS ON OVERSPEED AT BROWNS FERRY 2
TENNESSEE VALLEY AUTHORITY
LTR W/LER 79-015 TO U.S. NRC, REGION 2, JUL 05, 1979, DOCKET 50-260,
TYPE--BWR, MFG--GE, AE--TVA CONTROL--026192

DATE OF EVENT - 060779. POWER LEVEL - 074%. CAUSE - TRIP MECHANISM SET IMPROPERLY. WHILE PERFORMING SI 4.5.E, THE HPCI TRIPPED SEVERAL TIMES ON MECHANICAL OVERSPEED. THERE WERE NO PREVIOUS EVENTS OF THIS NATURE. INSPECTION OF THE OVERSPEED TRIP MECHANISM REVEALED THE TRIP WEIGHT HAD BEEN IMPROPERLY SET CAUSING DAMAGE TO THE BALL AND TAPPET ASSEMBLY. BALL AND TAPPET ASSEMBLY WAS REPLACED, TRIP WEIGHT PROPERLY SET, AND OVERSPEED TESTS RUN.

ACCESSION NUMBER 150964

HPCI STEAM ISOLATION VALVE BREAKER TRIPS AT BRUNSWICK 2
CAROLINA POWER & LIGHT CO.
LTR W/LER 79-053 TO U.S. NRC, REGION 2, AUG 17, 1979, DOCKET 50-324,
TYPE--BWR, MFG--GE, AE--UEC CONTROL--026521

DATE OF EVENT - 072179. POWER LEVEL - 000%. CAUSE - BINDING IN OPERATOR CAUSES MOTOR BURNOUT. WHILE PERFORMING PT 9.5, HPCI 1000# FLOW RATE TEST, THE HPCI STEAM ISOLATION VALVE F001 BREAKER TRIPPED WHILE CLOSING. THE -F001 MOTOR WAS FOUND BURNED UP DUE TO BINDING IN THE LIMITORQUE OPERATOR. ON INVESTIGATION, THE LIMITORQUE OPERATOR WAS FOUND WITH MOTOR PINION GEAR INSTALLED BACKWARD ON MOTOR SHAFT. THIS ALLOWED MOTOR PINION GEAR TO RIDE ON TRIPPER BUSHING WHEN IN OPERATION, THUS BINDING OPERATOR. SEVERAL COMPONENTS WERE DAMAGED IN OPERATOR AND WERE REPLACED.

ACCESSION NUMBER 151908

HPCI PUMP FAILS TO START ON AN AUTO START SIGNAL AT COOPER
NEBRASKA PUBLIC POWER DISTRICT
LTR W/LER 79-019 TO U.S. NRC, REGION 4, AUG 20, 1979, DOCKET 50-298,
TYPE--BWR, MFG--GE, AE--B+R CONTROL--026930

DATE OF EVENT - 080979. POWER LEVEL - 099%. CAUSE - NATURAL END OF LIFE. UPON RECEIPT OF AN AUTO START SIGNAL, THE HPCI (HIGH PRESSURE COOLANT INJECTION) PUMP DID NOT INITIALLY START. HOWEVER, A SHORT TIME LATER THE PUMP STARTED AND WAS USED TO INCREASE REACTOR LEVEL. THE RCIC SYSTEM WAS OPERABLE AND STARTED AS REQUIRED, AS WERE ALL LOW PRESSURE INJECTION SYSTEMS. THE EVENT IS NOT REPETITIVE. THE PISTON RINGS IN THE VALVE ACTUATOR FOR THE TURBINE STOP VALVE HAD DETERIORATED AND WERE ALLOWING OIL TO FLOW AROUND THE PISTON. THE RINGS WERE REPLACED AND A SIMULATED AUTO ACTUATION TEST (S.P. 6.3.3.3) WAS PERFORMED SATISFACTORILY. THE PREVENTIVE MAINTENANCE PROGRAM WAS REVISED TO REPLACE RINGS AND CHECK FOR RING LEAKAGE.

ACCESSION NUMBER 152934

HPCI SYSTEM FAILS AT BROWNS FERRY 1
TENNESSEE VALLEY AUTHORITY
LTR W/LER 79-027 TO U.S. NRC, REGION 2, NOV 07, 1979, DOCKET 50-259,
TYPE--BWR, MFG--GE, AE--TVA CONTROL--027316

DATE OF EVENT - 101079, POWER LEVEL - 098%, CAUSE - RUPTURE DISC FAILS. WITH UNIT AT STEADY STATE POWER OF 98 PERCENT, SURVEILLANCE INSTRUCTION 4.5.E.1.D WAS BEING RUN WHEN HIGH PRESSURE COOLANT INJECTION TURBINE TRIPPED DUE TO A FAILED RUPTURE DISC IN THE TURBINE EXHAUST LINE, RENDERING HPCI INOPERABLE. NO SIGNIFICANT RESULTING CHAIN OF EVENTS, AND NO PREVIOUS SIMILAR EVENT. THE TEFLON SHEET PORTION OF THE DISC FAILED, PROVIDING NO PROTECTION TO THE DISC UNDER VACUUM CONDITION. THE RUPTURE DISC WAS REPLACED AND A DCR ISSUED TO PURCHASE AN IMPROVED RUPTURE DISC. FIKE METAL PROD., 16" MDL PLHOV. TEFLON/S.S., 181 LBS. AT 378 DEGREES F.

ACCESSION NUMBER 153645

HPCI VALVE FAILS TO OPEN AT BROWNS FERRY 1
TENNESSEE VALLEY AUTHORITY
LTR W/LER 79-028 TO U.S. NRC, REGION 2, NOV 15, 1979, DOCKET 50-259,
TYPE--BWR, MFG--GE, AE--TVA CONTROL--027620

DATE OF EVENT - 101779, POWER LEVEL - 098%, CAUSE - DIRTY LIMIT SWITCH CONTACTS. DURING NORMAL OPERATIONS, WHILE PERFORMING SI 4.5.E.1.C, FCV 73-27 WOULD NOT OPEN, RESULTING IN HPCI SYSTEM INOPERABILITY. REDUNDANT SYSTEMS WERE AVAILABLE. PREVIOUS OCCURRENCES: NONE. DIRTY CONTACTS ON FCV 73-27 LIMITORQUE OPERATOR (TYPE 4T4G) LIMIT SWITCHES PREVENTED VALVE OPERATION. THE LIMIT SWITCH CONTACTS WERE CLEANED AND THE SI COMPLETED SATISFACTORILY.

ACCESSION NUMBER 154019

HPCI SYSTEM ISOLATES ON HIGH SUCTION PRESSURE SIGNAL AT BRUNSWICK 1
CAROLINA POWER & LIGHT CO.
LTR W/LER 79-104 TO U.S. NRC, REGION 2, DEC 28, 1979, DOCKET 50-325,
TYPE--BWR, MFG--GE, AE--UEC CONTROL--027838

DATE OF EVENT - 120679, POWER LEVEL - 013%, CAUSE - LEAKING DIAPHRAGM. WHILE PERFORMING HPCI 1000# FLOW RATE TEST, THE HPCI SYSTEM ISOLATED DUE TO A HIGH SUCTION PRESSURE SIGNAL FROM 1E41-PSH-N031. THE DIAPHRAGM ON 1E41-PSH-N031 WAS FOUND TO BE LEAKING, THUS PROVIDING A FALSE HIGH PRESSURE SIGNAL. THE DIAPHRAGM WAS REPLACED AND RETURNED TO SERVICE SATISFACTORILY. THIS SWITCH IS CHECKED ON A QUARTERLY BASIS PER THE CALIBRATION PROGRAM. THIS IS CONSIDERED AN ISOLATED EVENT.

ACCESSION NUMBER 154770

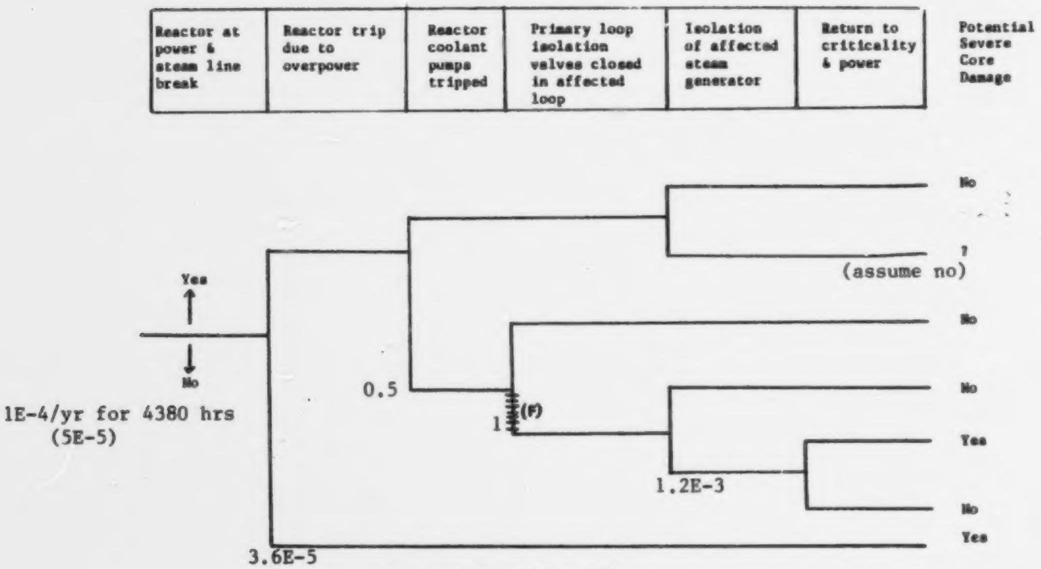
HPCI INJECTION VALVE FAILS TO OPERATE AT BRUNSWICK 1
CAROLINA POWER & LIGHT CO., RALEIGH, NC
3 PGS, LTR W/LER 1-79-88 TO NRC, REGION II, NOV. 19, 1979, DOCKET 50-325,
TYPE--BWR, MFG--GE, AE--UE&C

DATE OF EVENT - 102579. POWER LEVEL - 050%. CAUSE - MISSING DRIVE GEAR LOCKWIRE. WHILE PERFORMING HPCI SYSTEM COMPONENT TEST, THE CONTROL OPERATOR NOTICED THAT THE HPCI INJECTION VALVE F006 COULD NOT BE OPERATED FROM THE RTGB. AN INVESTIGATION OF THE VALVE OPERATOR DETERMINED THAT LOCKWIRE WAS MISSING FROM THE DRIVE GEAR WITH RESULTANT LOOSENING OF THE SET SCREW WHICH ALLOWED THE DRIVE GEAR KEY TO COME OUT OF ITS KEYWAY. THE OPERATOR WAS REASSEMBLED CORRECTLY AND TESTED. NO REASON COULD BE DETERMINED FOR THE MISSING LOCKWIRE.

BEST DOCUMENT AVAILABLE

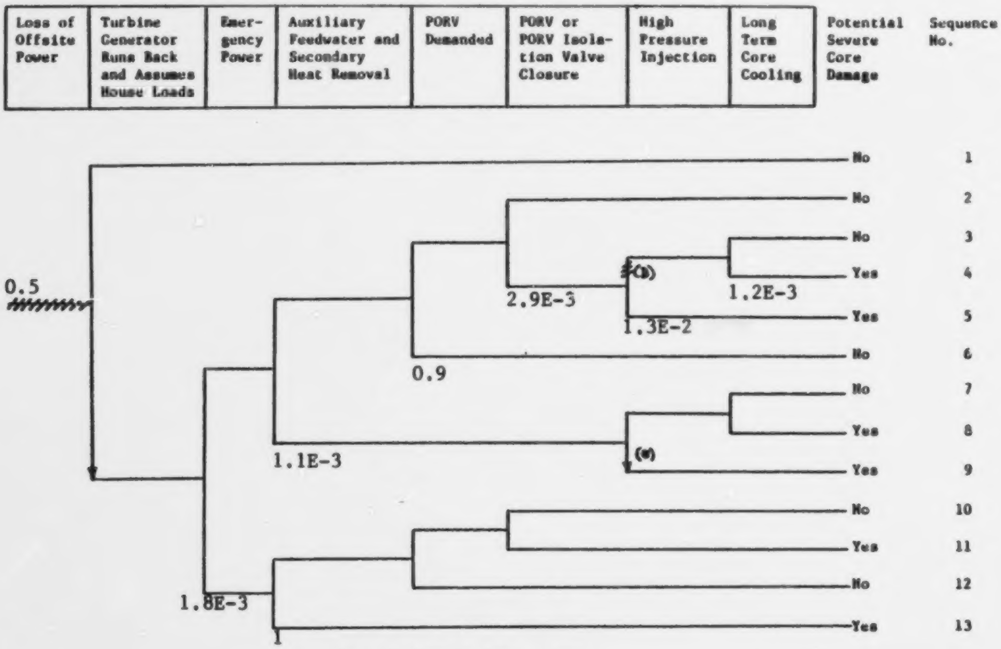
Precursor Probability Measure Calculations

The precursor probability measures (P) listed below each event tree are calculated based on those event tree sequences impacted by the precursor event. See Sect. 4.2 for calculational details.


Reactor at power & steam line break
Reactor trip due to overpower
Reactor coolant pumps tripped
Primary loop isolation valves closed in affected loop
Isolation of affected steam generator
Return to criticality & power
Potential Severe Core Damage
Yes
No
1E-4/yr for 4380 hrs
(5E-5)
0.5
1
(F)
1.2E-3
3.6E-5
No
?
(assume no)
No
No
Yes
No
Yes

P = 3.2E-8 (SC = 75)

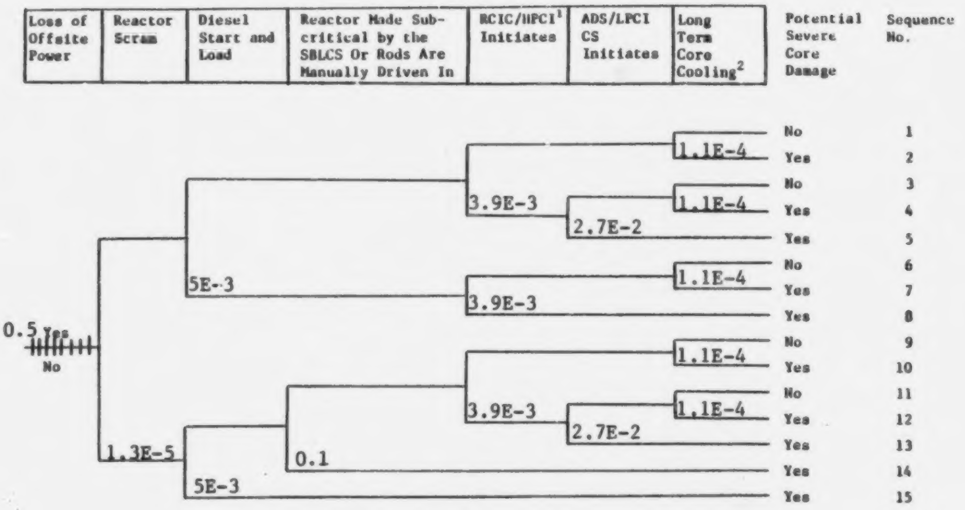
NSIC 32429 — Sequence of Interest for Loop Isolation Valve Failure at Indian Point 1


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
2.9E-3
(a)
1.2E-3
1.3E-2
0.9
1.1E-3
(a)
1.8E-3
1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1.45E-3 (SC = 28)

NSIC 36147 — Sequence of Interest for Loss of Offsite Power and load Rejection at Haddam Neck

[a] Use of HPI after failure of AFW was not included in mitigation procedure.

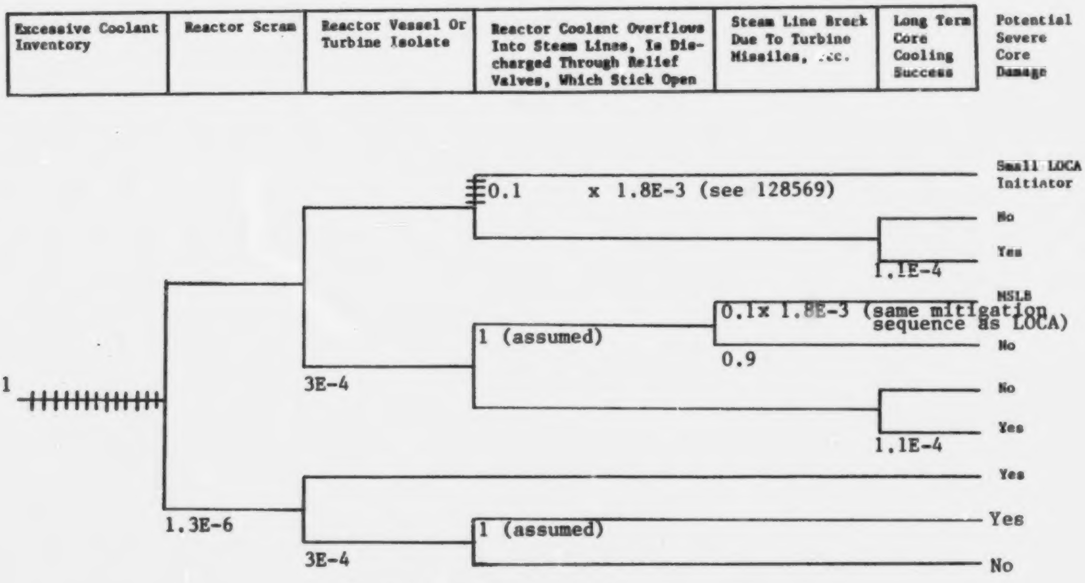

Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI[1] Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling[2]
Potential Severe Core Damage
Sequence No.
0.5 Yes
No
1.3E-5
5E-3
5E-3
0.1
3.9E-3
3.9E-3
3.9E-3
2.7E-2
2.7E-2
1.1E-4
1.1E-4
1.1E-4
1.1E-4
1.1E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 1.25E-4 (SC = 39)

NSIC 39024 – Sequence of Interest of Loss of Offsite Power and Other Failures at Big Rock Point

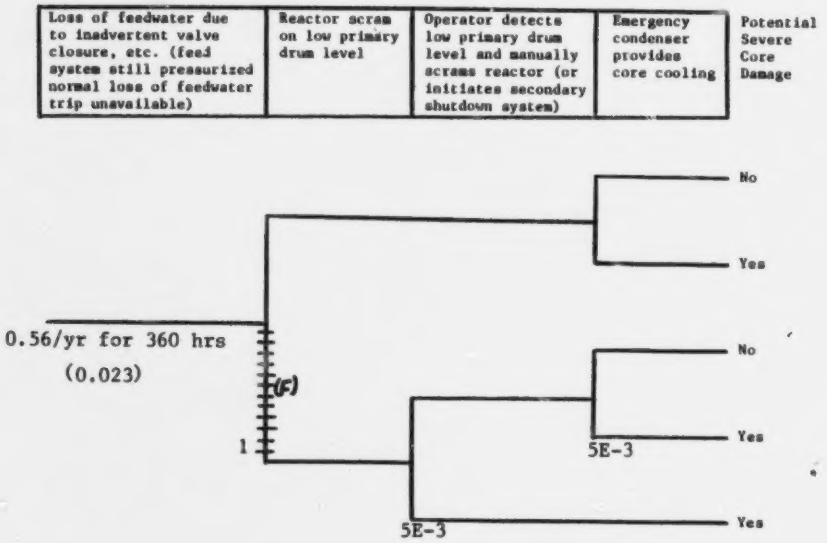
[1] Big Rock Point utilizes isolation condenser instead of RCIC

[2] Success requires return of A.C. power within a day.


Excessive Coolant Inventory
Reactor Scram
Reactor Vessel Or Turbine Isolate
Reactor Coolant Overflows Into Steam Lines, Is Discharged Through Relief Valves, Which Stick Open
Steam Line Break Due To Turbine Missiles, etc.
Long Term Core Cooling Success
Potential Severe Core Damage
1
0.1 x 1.8E-3 (see 128569)
Small LOCA Initiator
No
Yes
1.1E-4
MSLB
0.1x 1.8E-3 (same mitigation sequence as LOCA)
1 (assumed)
0.9
No
3E-4
No
Yes
1.1E-4
Yes
1.3E-6
1 (assumed)
Yes
3E-4
No

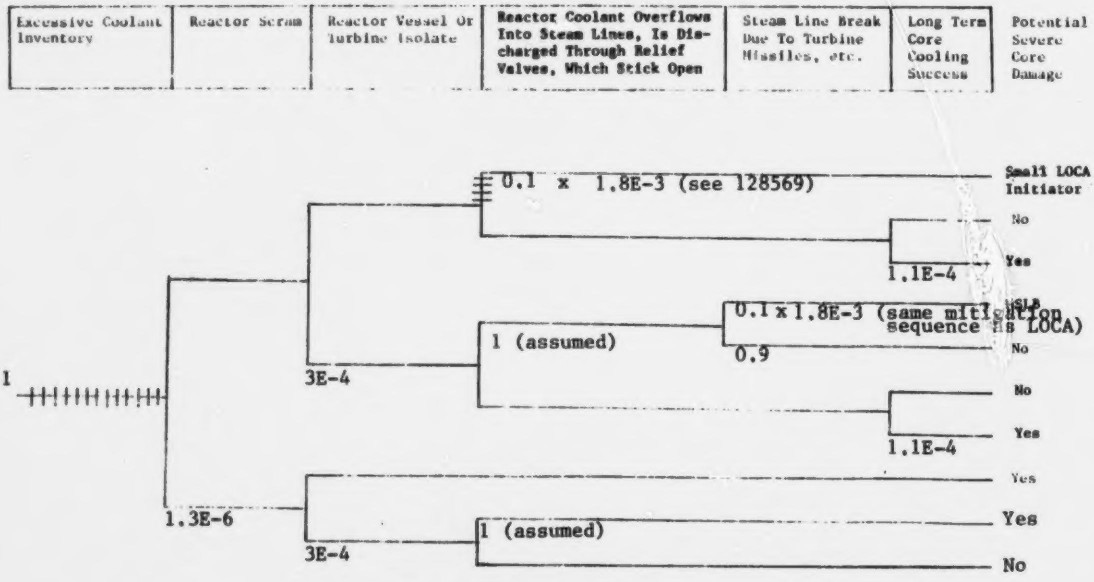
P = 2.8E-4 (SC = 36)

NSIC 39380 – Sequence of Interest for Safety Valve Actuation After Feedwater Transient at Dresden 3


Loss of feedwater due to inadvertent valve closure, etc. (feed system still pressurized normal loss of feedwater trip unavailable)
Reactor scram on low primary drum level
Operator detects low primary drum level and manually scrams reactor (or initiates secondary shutdown system)
Emergency condenser provides core cooling
Potential Severe Core Damage
No
Yes
No
Yes
Yes
0.56/yr for 360 hrs
(0.023)
(F)
1
5E-3
5E-3

P = 2.3E-4 (SC = 36)

NSIC 44751 — Sequence of Interest for Failure of Three of Four Safety System Sensors for Primary Drum Level Scram at Dresden 1

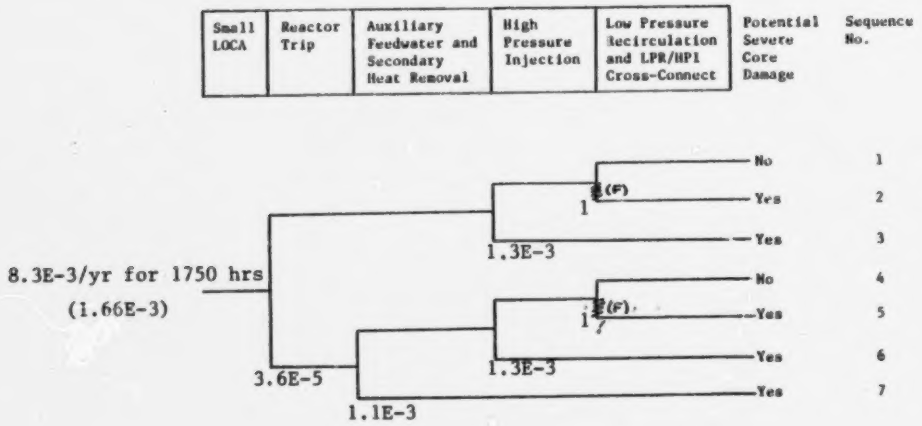

Excessive Coolant Inventory
Reactor Scram
Reactor Vessel Or Turbine Isolate
Reactor Coolant Overflows Into Steam Lines, Is Discharged Through Relief Valves, Which Stick Open
Steam Line Break Due To Turbine Missiles, etc.
Long Term Core Cooling Success
Potential Severe Core Damage
0.1 x 1.8E-3 (see 128569)
Small LOCA Initiator
No
Yes
1.1E-4
NSLB
0.1 x 1.8E-3 (same mitigation sequence as LOCA)
1 (assumed)
0.9
No
3E-4
1
No
Yes
1.1E-4
Yes
1.3E-6
Yes
1 (assumed)
3E-4
No

P = 2.8E-4 (SC = 36)

NSIC 47814 — Sequence of Interest for the Depressurization Incident at Dresden 2

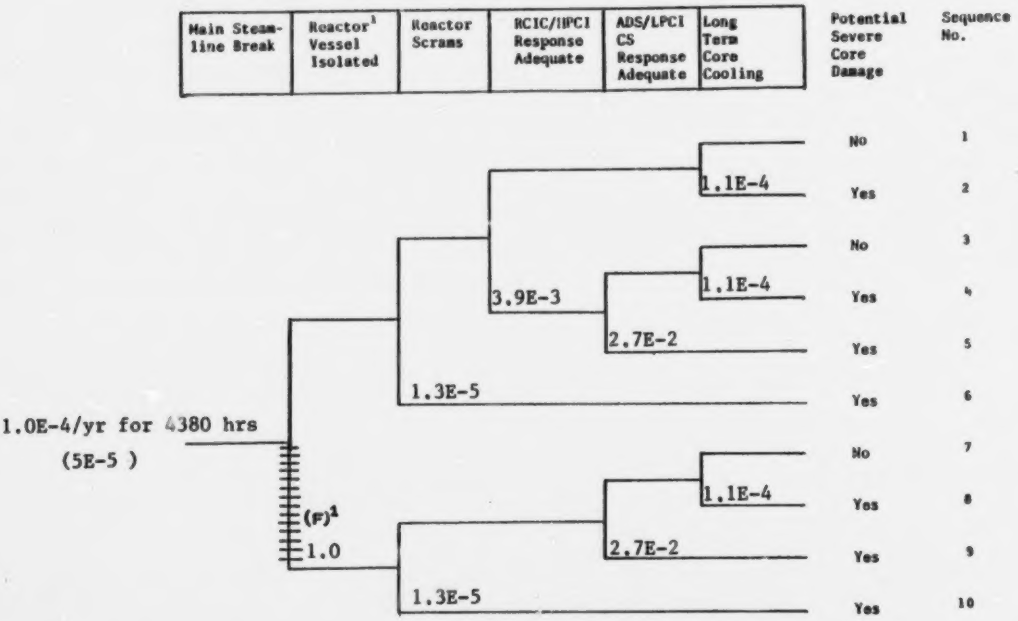
BEST DOCUMENT AVAILABLE 124

[redacted]


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
8.3E-3/yr for 1750 hrs
(1.66E-3)
1.3E-3
1 (F)
3.6E-5
1.3E-3
1 (F)
1.1E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 1.66E-3 + addl. cont (LOFW), 3.3E-5 = 1.7E-3 (SC = 28)

NSIC 59484 – Sequence of Interest for Failure of Sump Isolation Valves at Point Beach 1

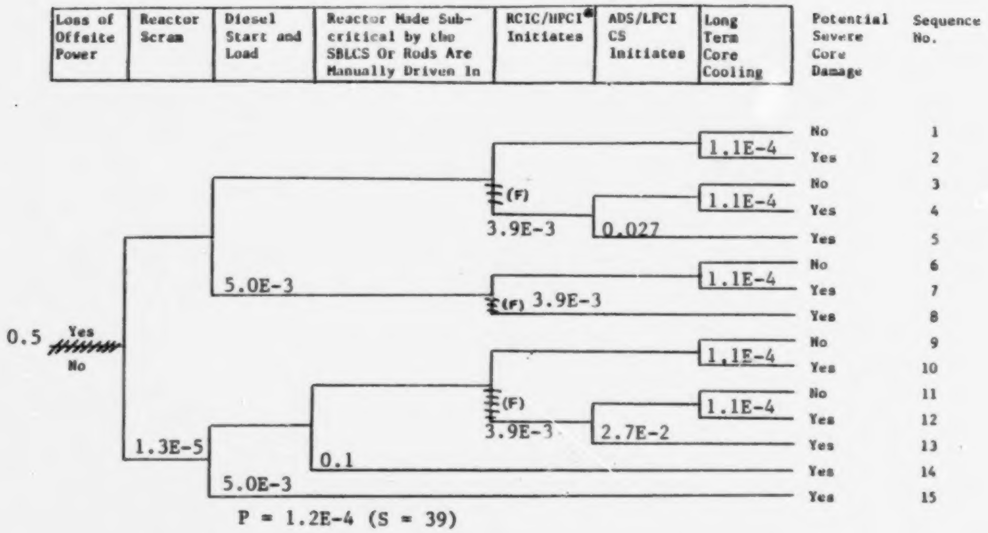

Main Steam-line Break
Reactor Vessel Isolated
Reactor Scrams
RCIC/HPCI Response Adequate
ADS/LPCI CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0E-4/yr for 4380 hrs
(5E-5)
1.1E-4
3.9E-3
1.1E-4
2.7E-2
1.3E-5
(F)1
1.0
1.1E-4
2.7E-2
1.3E-5
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
No 7
Yes 8
Yes 9
Yes 10

P = 1.35E-6 (SC = 59)

NSIC 60227 – Sequence of Interest for Failure of Several MSIV's at Dresden 2

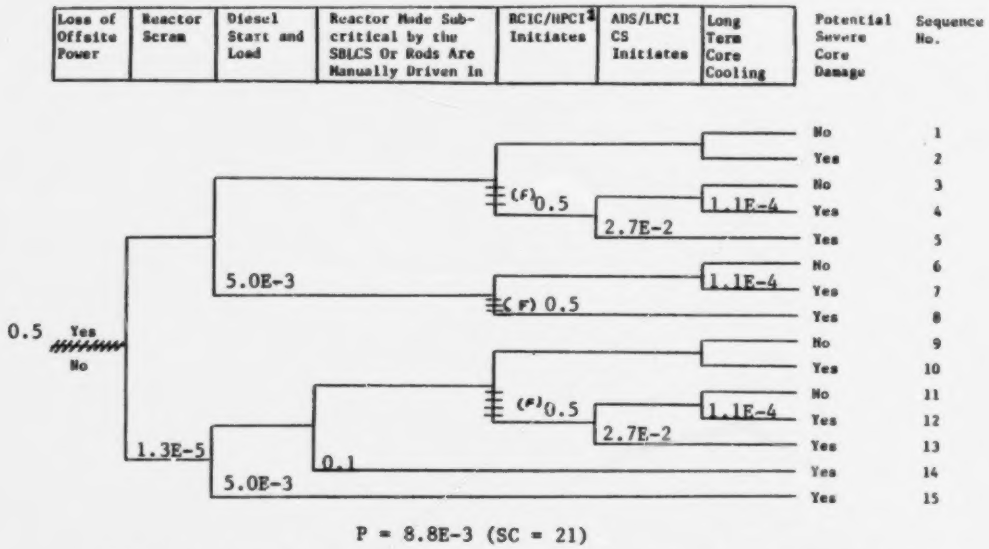
[1] A failed state would result if the steamline break was between the two MSIV's on the D steam line. The failed MSIVs could just as easily occurred on any steam line.

125 BEST DOCUMENT AVAILABLE


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI* Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
Yes
No
1.3E-5
5.0E-3
0.1
(F)
3.9E-3
0.027
2.7E-2
1.1E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15
P = 1.2E-4 (S = 39)

NSIC 61043 — Sequence of Interest for Plant Electrical Power Failure at La Crosse

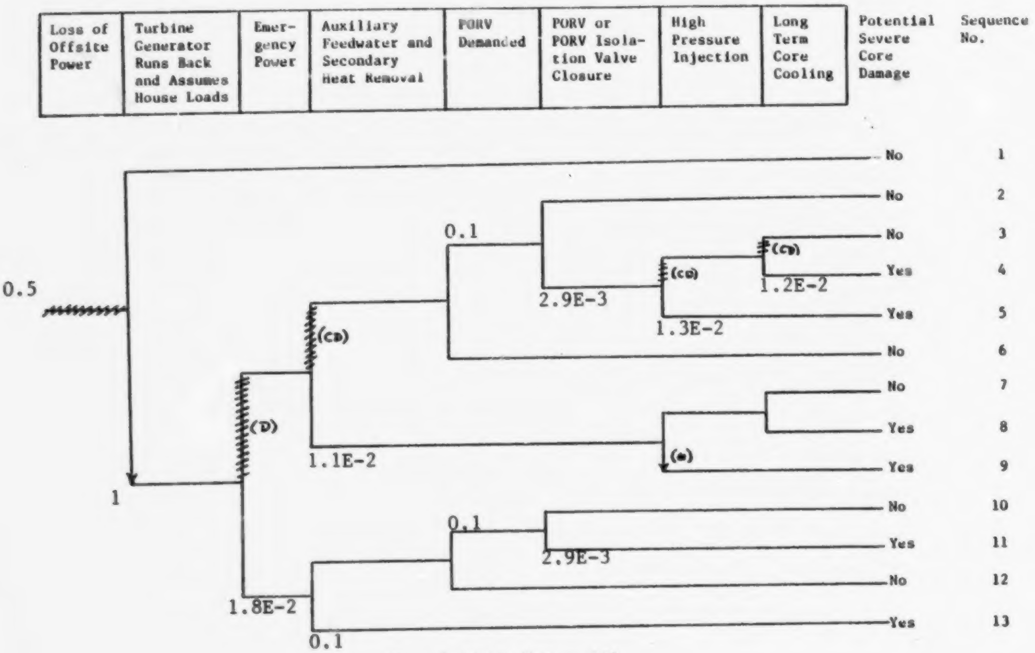
*La Crosse utilizes shutdown condenser and condensate pumps instead of RCIC and HPCI.


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI1 Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
Yes
No
1.3E-5
5.0E-3
0.1
(F) 0.5
2.7E-2
1.1E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15
P = 8.8E-3 (SC = 21)

NSIC 61434 — Sequence of Interest for Loss of Offsite Power and Failure of an Emergency Condenser Valve to Open at Humboldt Bay

[1] Humboldt Bay utilized an emergency condenser and CRD hydraulic pumps/safety valves for decay heat removal

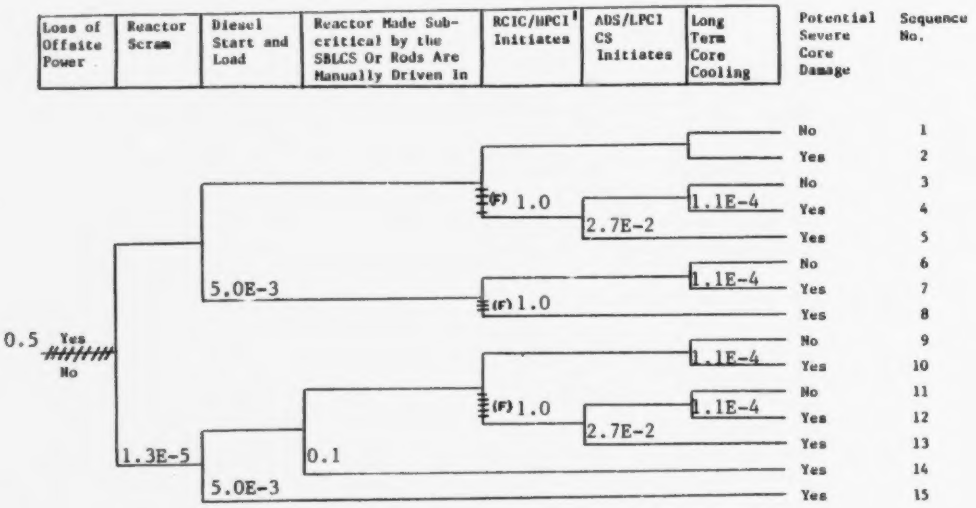
BEST DOCUMENT AVAILABLE


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1
(D)
(CD)
0.1
2.9E-3
(CD)
1.3E-2
(CD)
1.2E-2
1.1E-2
(*)
1.8E-2
0.1
2.9E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 6.4E-3 (SC = 22)

NSIC 61565 – Sequence of Interest for Loss of Offsite Power and Failure of a Diesel Generator to Load at Palisades

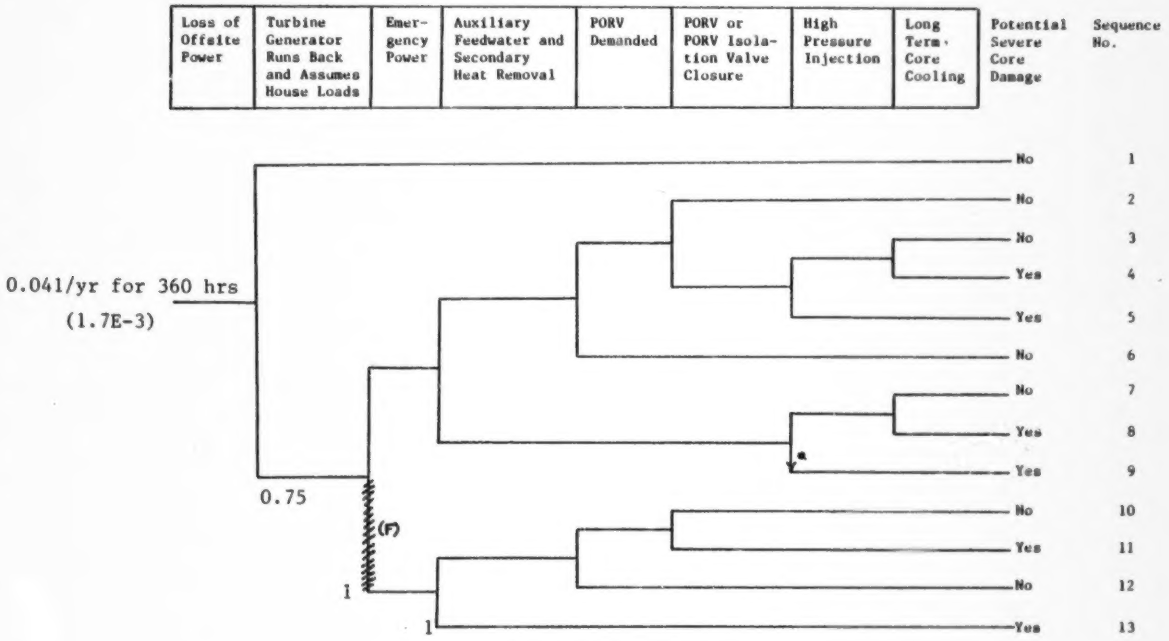
*Use of HPI following AFW failures not included in mitigation procedures.


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI¹ Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5 Yes
No
(F) 1.0
2.7E-2
1.1E-4
5.0E-3
(F) 1.0
1.1E-4
(F) 1.0
2.7E-2
1.1E-4
1.1E-4
1.3E-5
0.1
5.0E-3
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 1.8E-2 (SC = 18)

NSIC 63129 – Sequence of Interest for A Scram Caused by Electrical Load Rejection at La Crosse

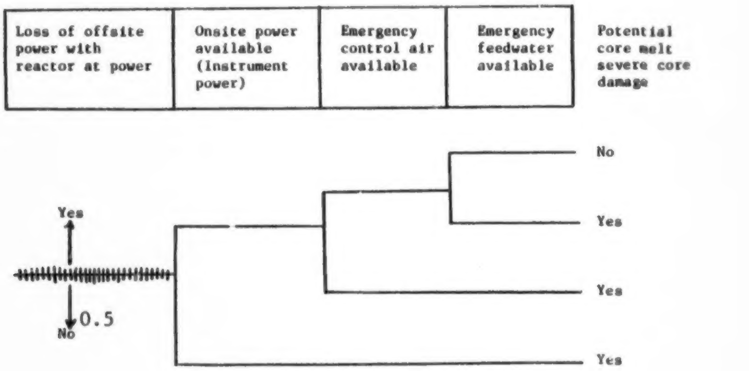
[1] La Crosse utilizes shutdown condenser and condensate pumps instead of RCIC and HPCI.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 360 hrs
(1.7E-3)
0.75
(F)
1
1
a
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1.3E-3 (SC = 29)

NSIC 63144 — Sequence of Interest for Both Diesel Generators Fail to Start at Robinson 2

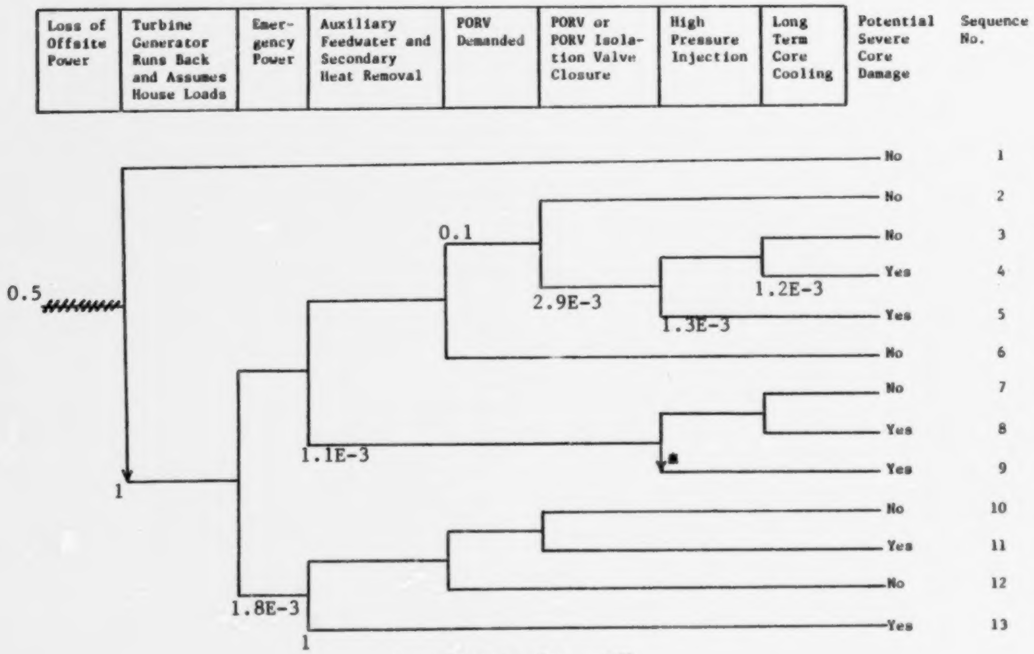
*not included in mitigation procedures


Loss of offsite power with reactor at power
Onsite power available (Instrument power)
Emergency control air available
Emergency feedwater available
Potential core melt severe core damage
Yes
No
0.5
No
Yes
Yes
Yes

P_{SCD} was assumed equal to other LOOP P_{SCD} s for plants with a turbine driven auxiliary feed pump

P = 5.7E-4 (SC = 32)

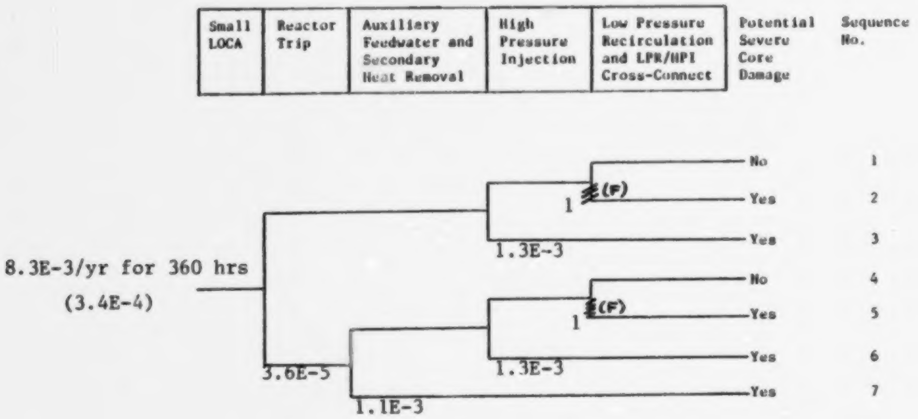
NSIC 64600 — Sequence of Interest for Loss of Offsite Power at Indian Point 1 (Operations Report No. 17)


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1
0.1
2.9E-3
1.3E-3
1.2E-3
1.1E-3
*
1.8E-3
1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1.45E-3 (SC = 28)

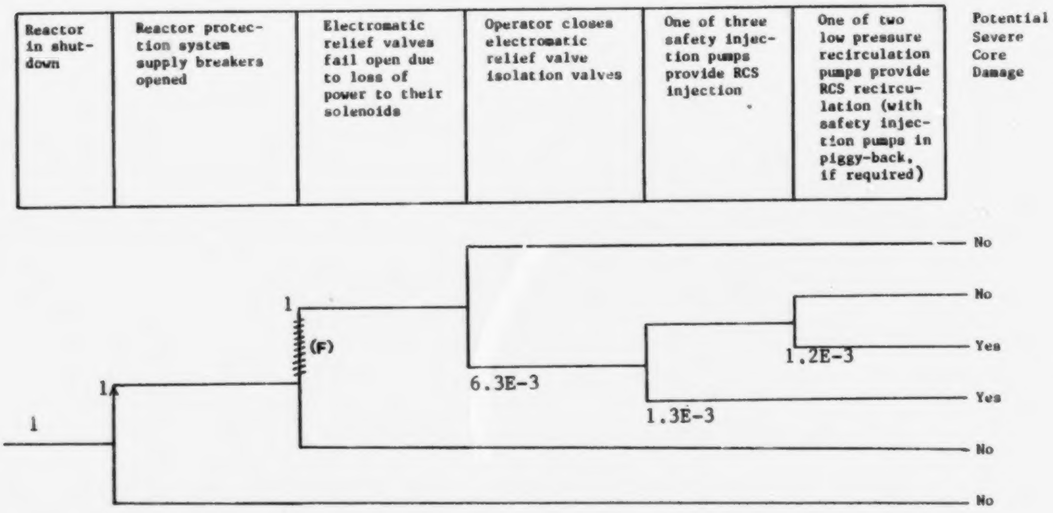
NSIC 65757 — Sequence of Interest for Loss of Offsite Power at Point Beach 1

*Not included in operating procedures


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
8.3E-3/yr for 360 hrs
(3.4E-4)
1
(F)
1.3E-3
1
(F)
1.3E-3
3.6E-5
1.1E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

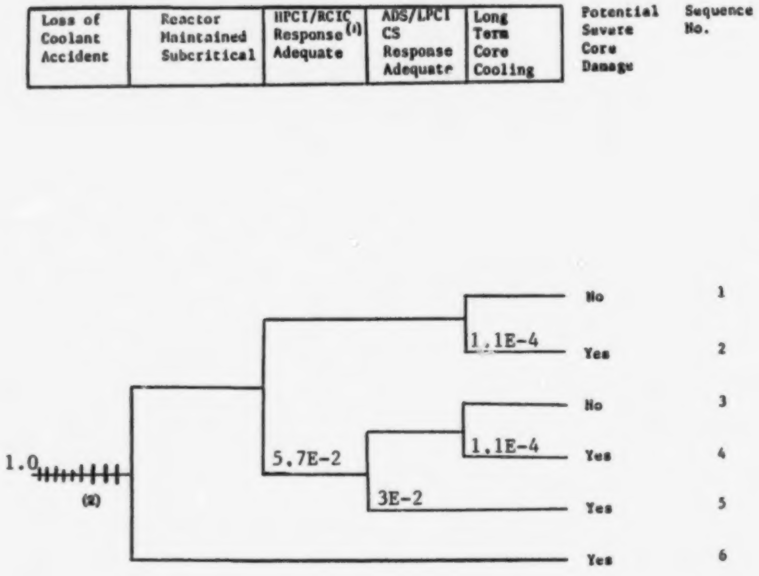
P = 3.4E-4 + addl. cont. (LOFW), 6.7E-6 = 3.5E-4 (SC = 35)

NSIC 65757 — Sequence of Interest for Failure of Containment Sump Isolation Valves at Point Beach 1


Reactor in shut-down
Reactor protection system supply breakers opened
Electromatic relief valves fail open due to loss of power to their solenoids
Operator closes electromatic relief valve isolation valves
One of three safety injection pumps provide RCS injection
One of two low pressure recirculation pumps provide RCS recirculation (with safety injection pumps in piggy-back, if required)
Potential Severe Core Damage
1
1
1
(F)
6.3E-3
1.3E-3
1.2E-3
No
No
Yes
Yes
No
No

P = 1.5E-5 x prob. of occurring at hot shutdown (0.75) = 1.1E-5 (SC = 49)

NSIC 65969 – Sequence of Interest for Unclear Wiring Diagrams Result in Depressurization at Palisades

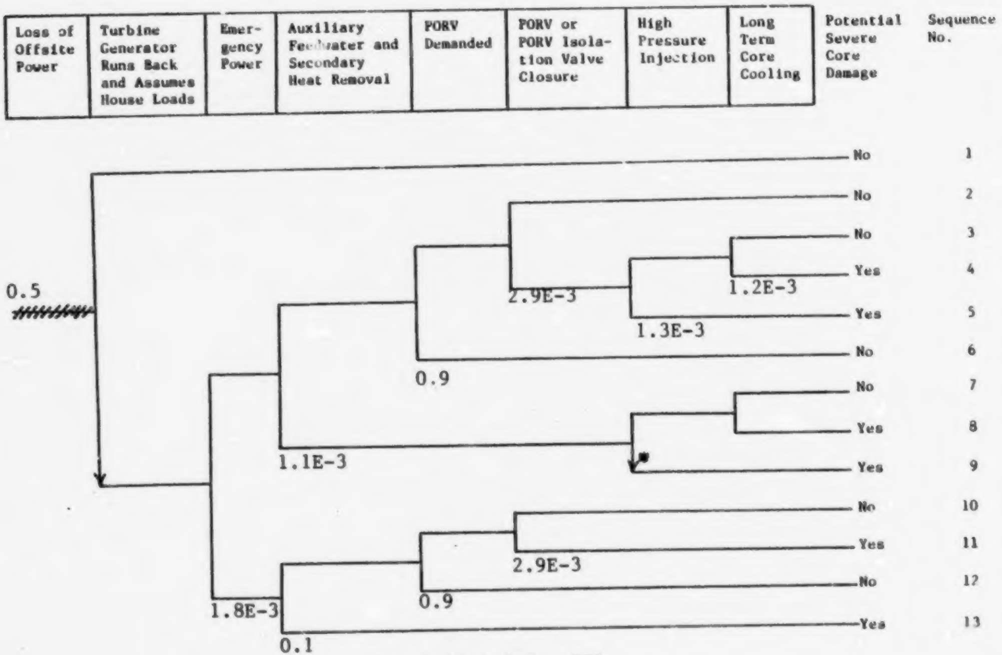

Loss of Coolant Accident
Reactor Maintained Subcritical
HPCI/RCIC Response Adequate (1)
ADS/LPCI CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
(2)
5.7E-2
3E-2
1.1E-4
1.1E-4
No
Yes
No
Yes
Yes
Yes
1
2
3
4
5
6

P = 1.8E-3 (SC = 27)

NSIC 66996 – Sequence of Interest for Pressure Transient and Blowdown at Millstone Point 1

[1] Millstone Point 1 utilizes IC, and FWCI instead of RCIC and HPCI.

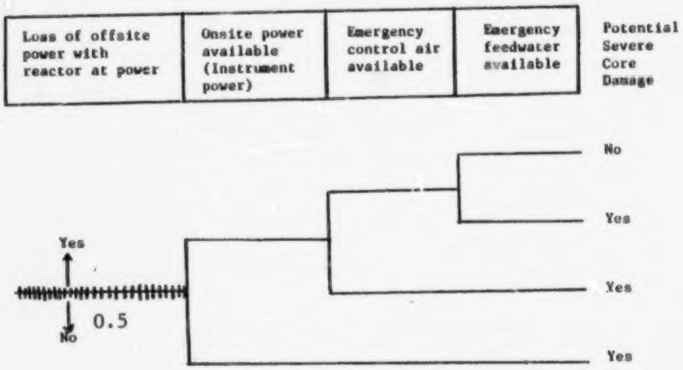
[2] Stuck open relief valve.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
0.9
2.9E-3
1.2E-3
1.3E-3
1.1E-3
*
1.8E-3
0.9
2.9E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 6.4E-4 (SC = 32)

NSIC 71694 — Sequence of Interest for Loss of Offsite Power at Palisades

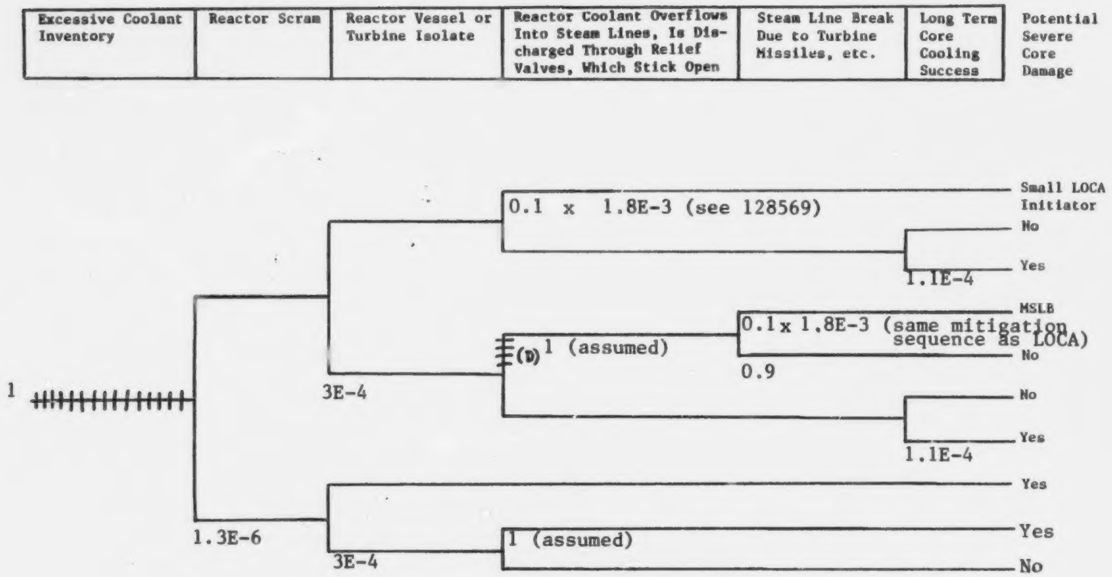
*Not included in operating procedures


Loss of offsite power with reactor at power
Onsite power available (Instrument power)
Emergency control air available
Emergency feedwater available
Potential Severe Core Damage
Yes
No
0.5
No
Yes
Yes
Yes

P_{SCD} was assumed equal to other LOOP P_{SCD}'s for plants with a turbine driven auxiliary feed pump

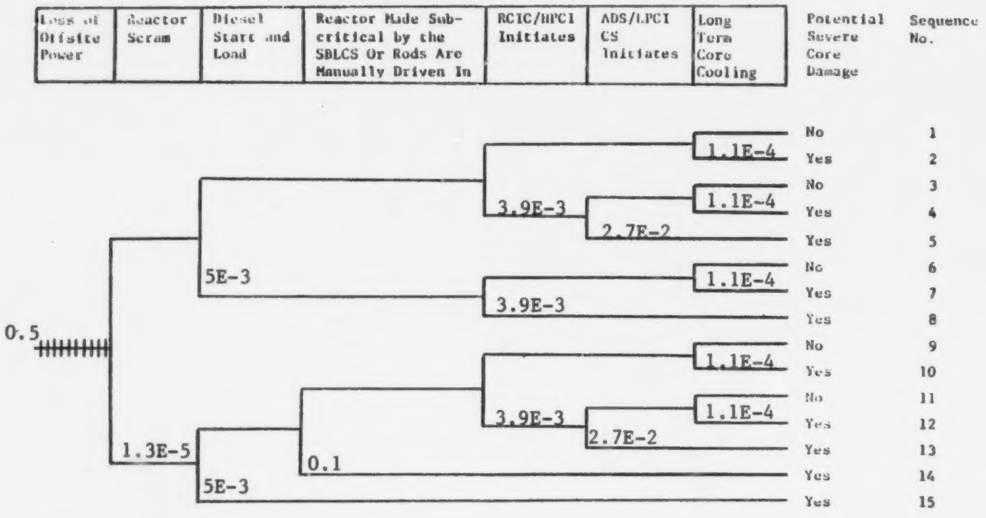
P = 5.7E-4 (SC = 32)

NSIC 73655 - Sequence of Interest for Loss of Offsite Power at Indian Point 1


Excessive Coolant Inventory
Reactor Scram
Reactor Vessel or Turbine Isolate
Reactor Coolant Overflows Into Steam Lines, Is Discharged Through Relief Valves, Which Stick Open
Steam Line Break Due to Turbine Missiles, etc.
Long Term Core Cooling Success
Potential Severe Core Damage
1
0.1 x 1.8E-3 (see 128569)
Small LOCA Initiator
No
Yes
1.1E-4
MSLB
0.1 x 1.8E-3 (same mitigation sequence as LOCA)
(D) 1 (assumed)
0.9
No
3E-4
No
Yes
1.1E-4
Yes
1.3E-6
1 (assumed)
Yes
3E-4
No

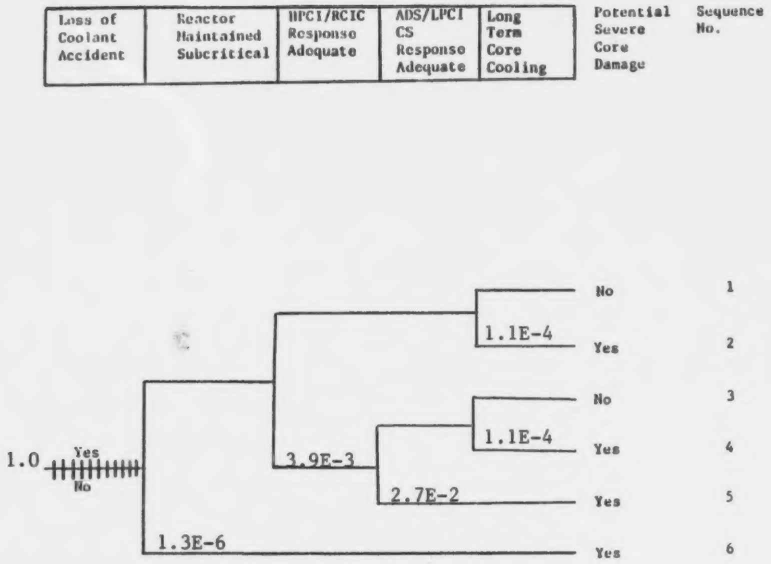
P = 2.8E-4 (SC = 36)

NSIC 74242 — Sequence of Interest for High Coolant Level at Nine Mile Point


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
No 1
1.1E-4
Yes 2
No 3
3.9E-3
1.1E-4
Yes 4
2.7E-2
Yes 5
5E-3
No 6
1.1E-4
Yes 7
3.9E-3
Yes 8
0.5
No 9
1.1E-4
Yes 10
No 11
3.9E-3
1.1E-4
Yes 12
2.7E-2
Yes 13
1.3E-5
0.1
Yes 14
5E-3
Yes 15

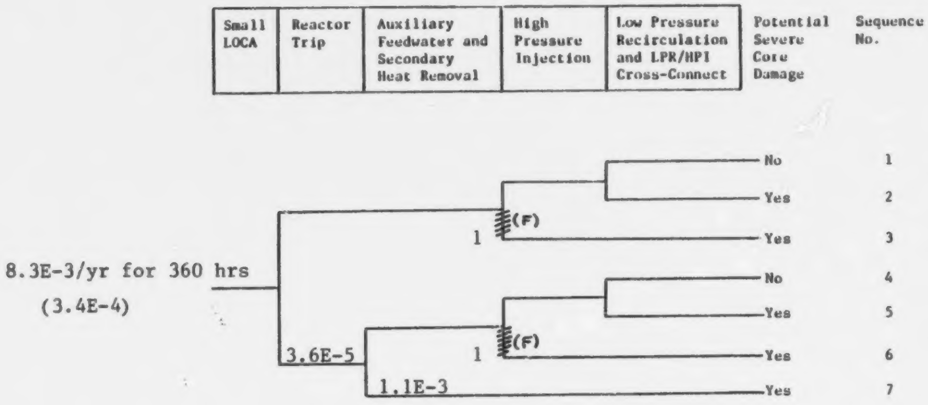
P = 1.2E-4 (SC = 39)

NSIC 75074 — Sequence of Interest for Loss of Load and Iodine Release at LaCrosse


Loss of Coolant Accident
Reactor Maintained Subcritical
HPCI/RCIC Response Adequate
ADS/LPCI CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
Yes
No
1.3E-6
3.9E-3
2.7E-2
1.1E-4
1.1E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6

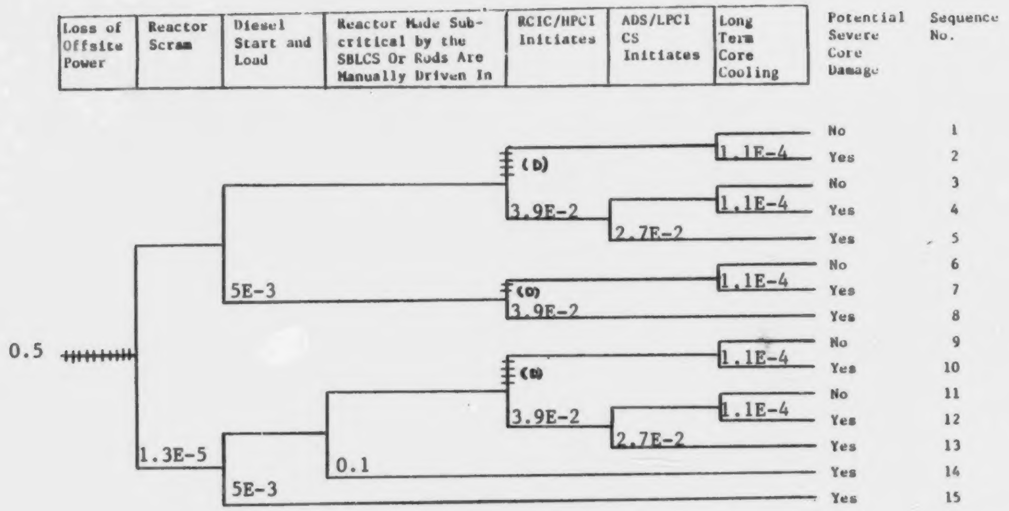
P = 2.1E-4 (SC = 37)

NSIC 77916 — Sequence of Interest for Several Valves Malfunctions at Oyster Creek


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
8.3E-3/yr for 360 hrs
(3.4E-4)
3.6E-5
1.1E-3
1
(F)
1
(F)
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

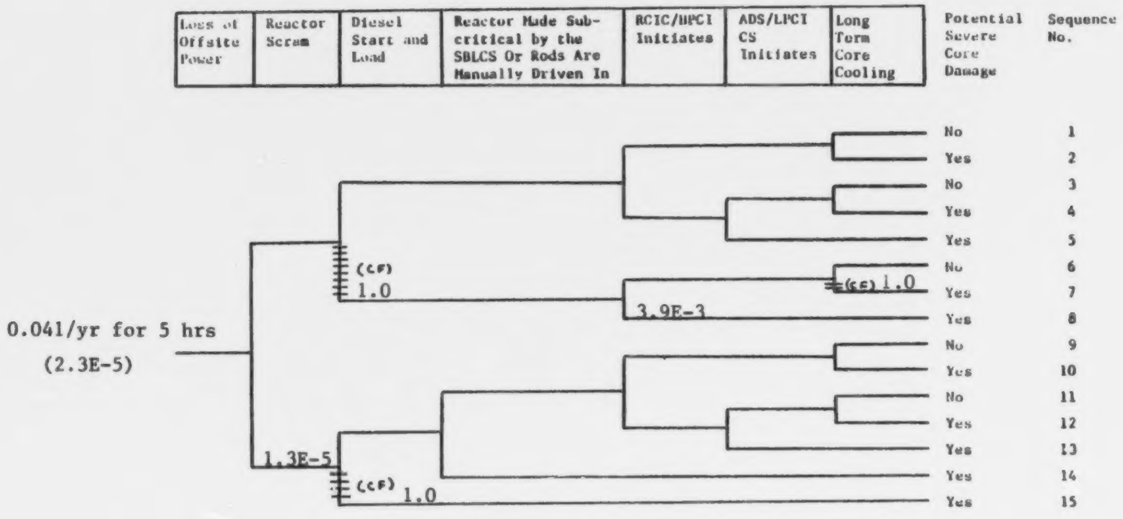
P = 3.4E-4 + addl. cont (LOFW), 6.7E-6 = 3.5E-4 (SC = 34)

NSIC 78418 — Sequence of Interest for Failure of Charging Pump Valves to Open After an Ice Storm at Maine Yankee


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
(D)
3.9E-2
2.7E-2
1.1E-4
5E-3
1.3E-5
0.1
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

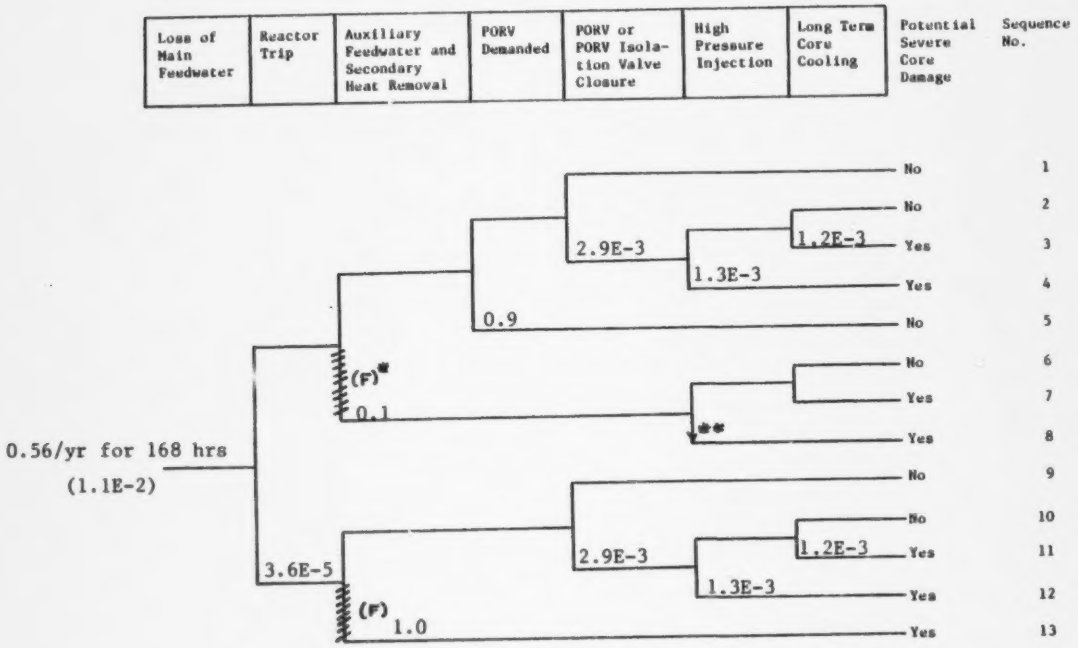
P (LOOP) = 6.8E-4 (SC = 32)

NSIC 79565 — Sequence of Interest of Loss of Normal Station Power Causes Cooling System Transient at Vermont Yankee


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 5 hrs
(2.3E-5)
(CF)
1.0
3.9E-3
1.3E-5
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 2.3E-5 + addl. cont. (LOFW, LOCA, MSLB), 5.1E-4 = 5.3E-4
x prob. of occurring at power (0.75) = 4.0E-4 (SC = 34)

NSIC 80138 — Sequence of Interest for Valve Problem Causes Flooding of Turbine Building Basement at Quad Cities 1

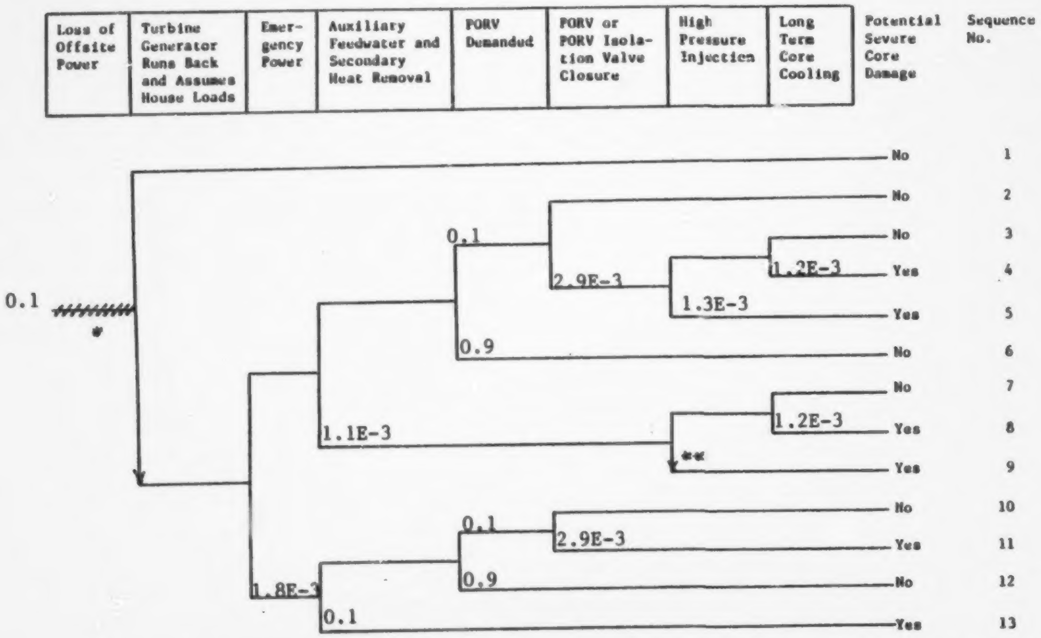

Loss of Main Feedwater
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.56/yr for 168 hrs
(1.1E-2)
2.9E-3
1.2E-3
1.3E-3
0.9
(F)*
0.1
**
3.6E-5
2.9E-3
1.2E-3
1.3E-3
(F)
1.0
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

P = 1.1E-3 + addl. cont. (LOOP), 7.9E-5 = 1.2E-3 (SC = 29)

NSIC 81523 – Sequence of Interest for Failure of AFW Pumps to Auto-Start at Turkey Point 4

*Success requires manual start

**Not included in operating procedures

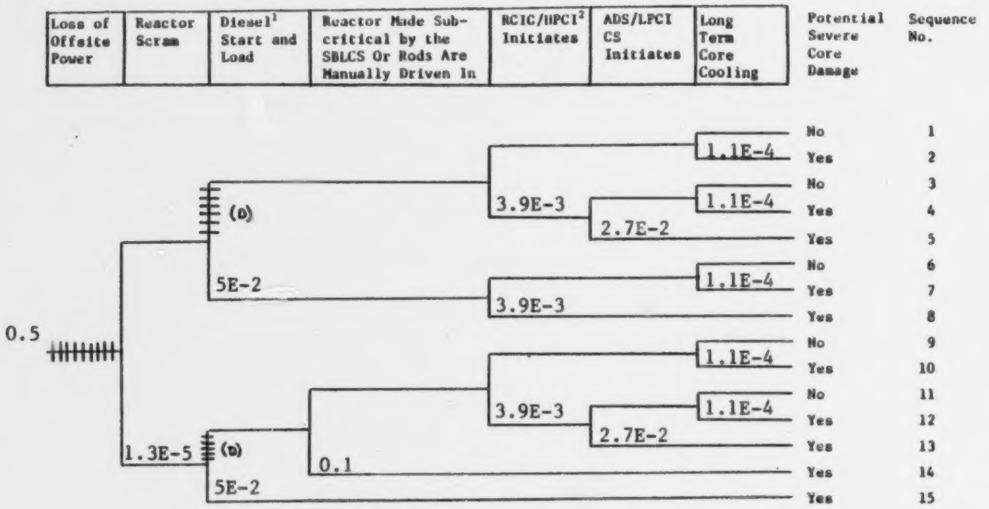

Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.1
*
0.1
2.9E-3
1.2E-3
1.3E-3
0.9
1.1E-3
1.2E-3
**
0.1
2.9E-3
0.9
1.8E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

NSIC 82198 – Sequence of Interest for Failure to Transfer Auxiliary Power to Startup Transformers at Turkey Point 3 (effective loss of offsite power)

*Success requires manual transfer to the startup transformer.
**Not included in mitigation procedures.

P = 1.28E-4 (SC = 39)

[redacted]

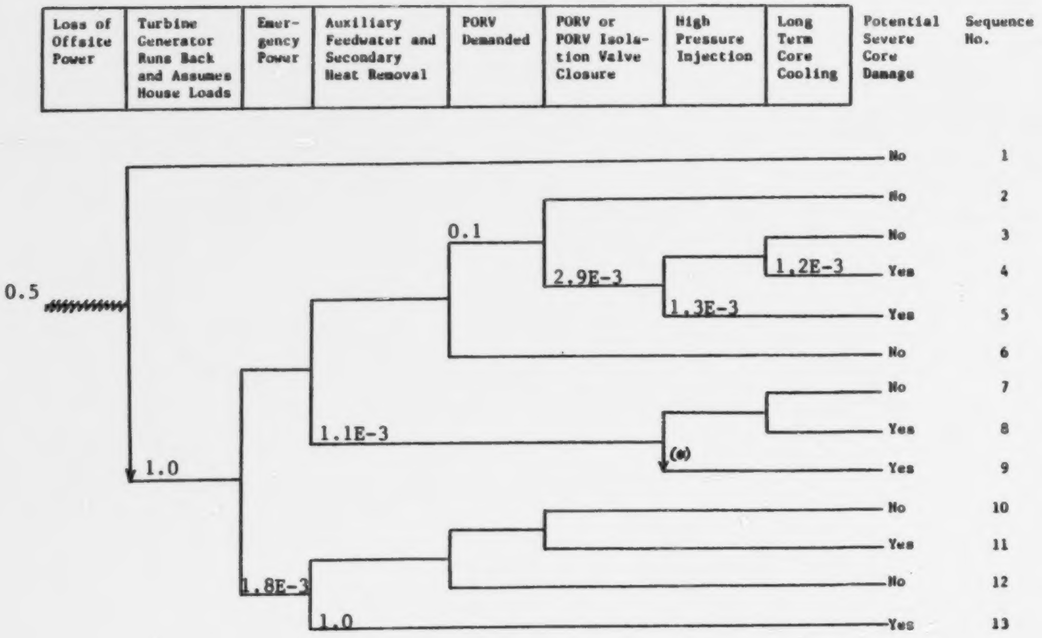

Loss of Offsite Power
Reactor Scram
Diesel¹ Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI² Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
(D)
5E-2
3.9E-3
1.1E-4
2.7E-2
1.3E-5
(D)
0.1
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 2E-4 (SC = 37)

NSIC 83833 — Sequence of Interest for a Total Loss of A.C. Power at Oyster Creek

[1] Diesel had initiated earlier in the transient but was locked out after being secured. The total loss of a.c. power lost approximately 15 sec.

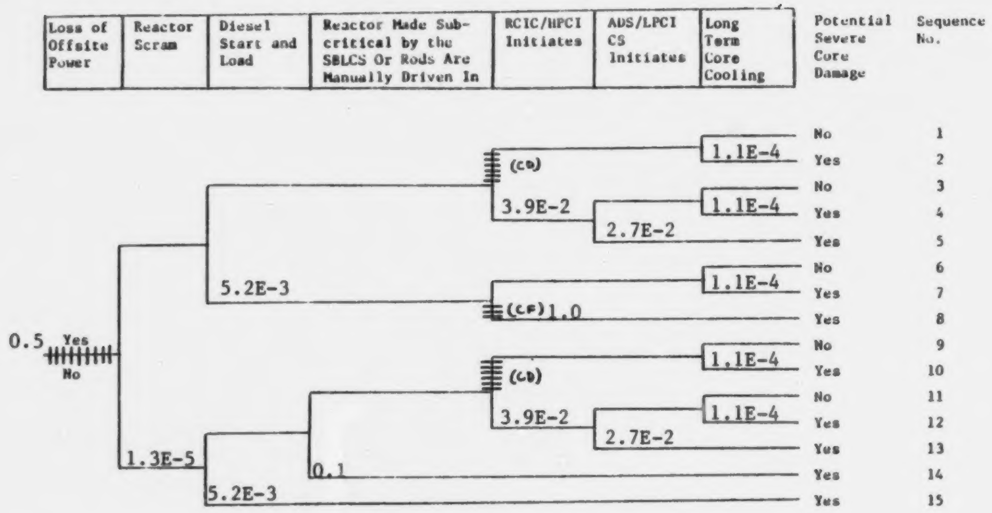
[2] Oyster Creek utilizes isolation condenser rather than RCIC.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
(*)
1.8E-3
1.0
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1.45E-3 (SC = 28)

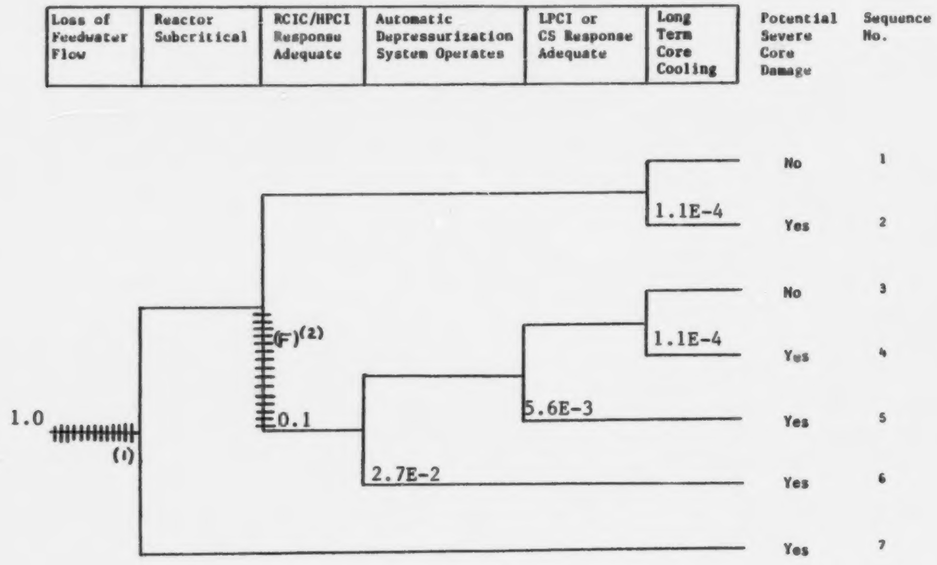
NSIC *5370 — Sequence of Interest for Loss of Offsite Power at R. E. Ginna

*Use of HPI following AFW failure not included in mitigation procedures.


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
Yes
No
(CD)
3.9E-2
2.7E-2
1.1E-4
1.1E-4
5.2E-3
(CF)
1.0
1.1E-4
(CD)
3.9E-2
2.7E-2
1.1E-4
1.1E-4
1.3E-5
0.1
5.2E-3
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 3.1E-3 (SC = 25)

NSIC 85566 – Sequence of Interest for Complete Loss of Plant A.C. Power Caused RCIC and HPCI to be Inoperable at Browns Ferry 1

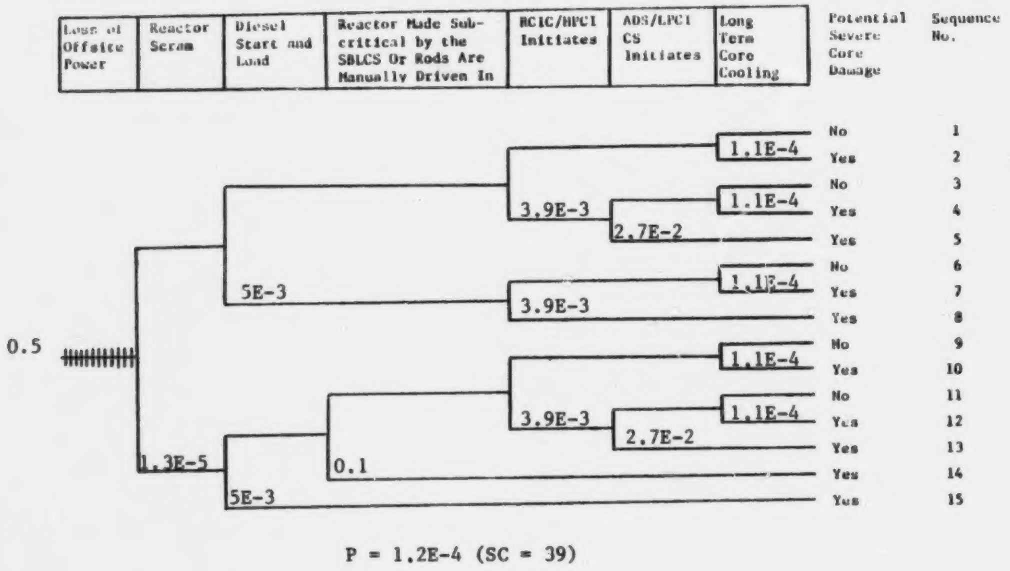

Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
(1)
(F)(2)
0.1
1.1E-4
1.1E-4
5.6E-3
2.7E-2
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 3.4E-3 (SC = 25)

NSIC 85738 – Sequence of Interest for RCIC and HPCI Failures During Testing at Browns Ferry 1

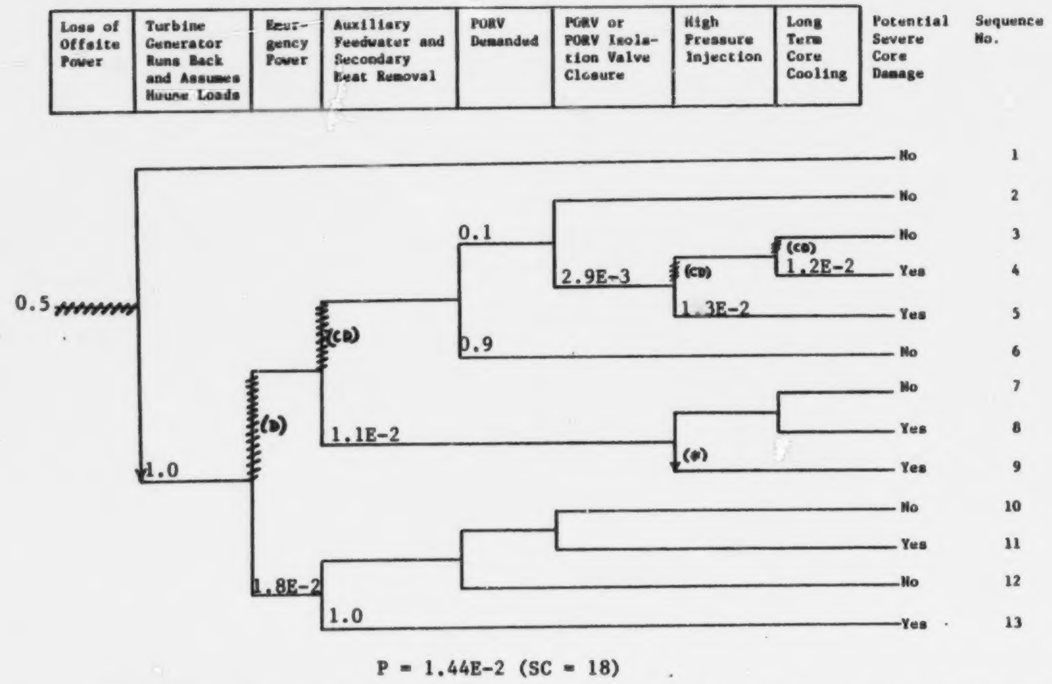
[1] An apparent loss of feedwater.

[2] HPCI was manually reset and operated satisfactorily.



Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
5E-3
1.3E-5
0.1
5E-3
3.9E-3
3.9E-3
3.9E-3
2.7E-2
2.7E-2
1.1E-4
1.1E-4
1.1E-4
1.1E-4
1.1E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15
P = 1.2E-4 (SC = 39)

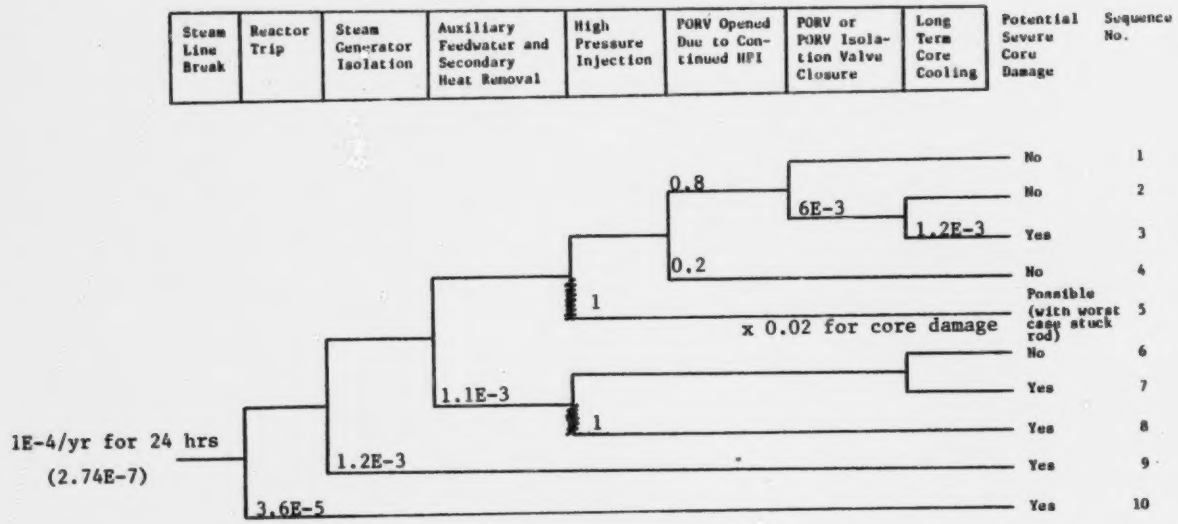
NSIC 86990 — Sequence of Interest of Loss of Incoming Power of Nine Mile Point from Worker Bumping Relay



Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
(b)
(CD)
0.1
0.9
2.9E-3
(CD)
1.3E-2
(CD)
1.2E-2
1.1E-2
(*)
1.8E-2
1.0
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13
P = 1.44E-2 (SC = 18)

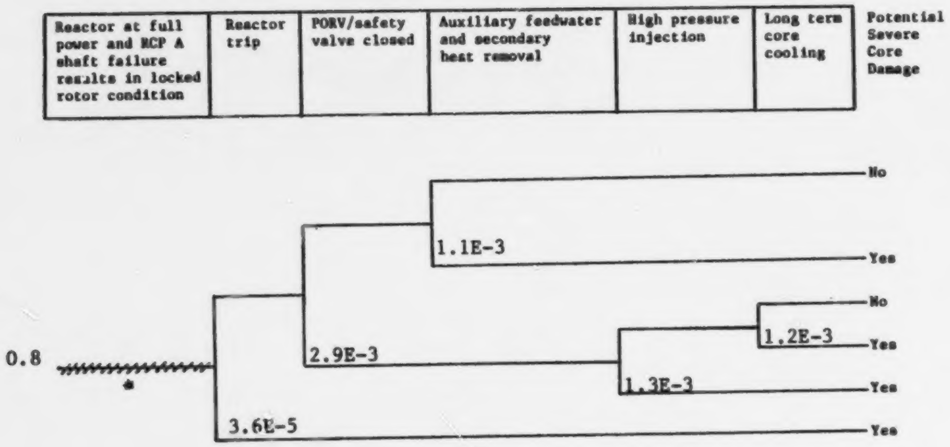
NSIC 88451 — Sequence of Interest for Total Loss of Station Service Power and Failure of Service Water Pump for One Diesel-Generator at Connecticut Yankee

*Use of HPI following loss of AFW was not included in mitigation procedures.


Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.8
6E-3
1.2E-3
0.2
1
x 0.02 for core damage
1.1E-3
1
1E-4/yr for 24 hrs
(2.74E-7)
1.2E-3
3.6E-5
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

P = 5.8E-9 (SC = 82)

NSIC 89153 — Sequence of Interest for Inadvertent Opening of RWST Isolation Valves at Prairie Island 1

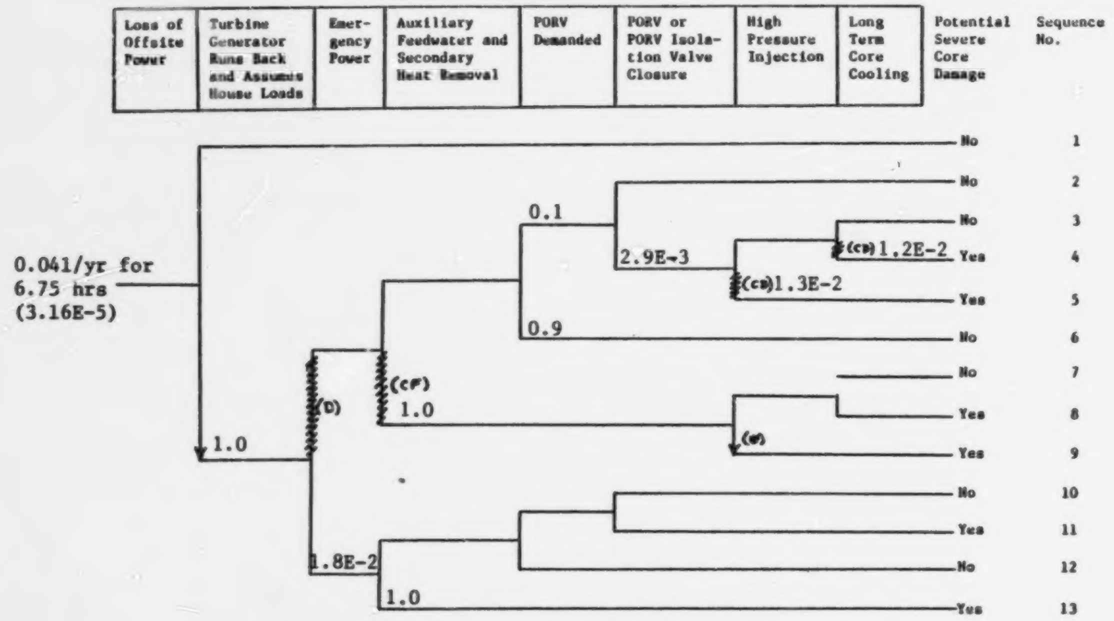

Reactor at full power and RCP A shaft failure results in locked rotor condition
Reactor trip
PORV/safety valve closed
Auxiliary feedwater and secondary heat removal
High pressure injection
Long term core cooling
Potential Severe Core Damage
0.8
*
1.1E-3
2.9E-3
1.2E-3
1.3E-3
3.6E-5
No
Yes
No
Yes
Yes
Yes

P = 9.12E-4 (SC = 30)

NSIC 89205 — Sequence of Interest for Failure of a Reactor Coolant Pump Shaft at Surry 1

*Surry pump failure at full power instead of at 42% power and with perhaps a more abrupt stopping of the pump impeller.

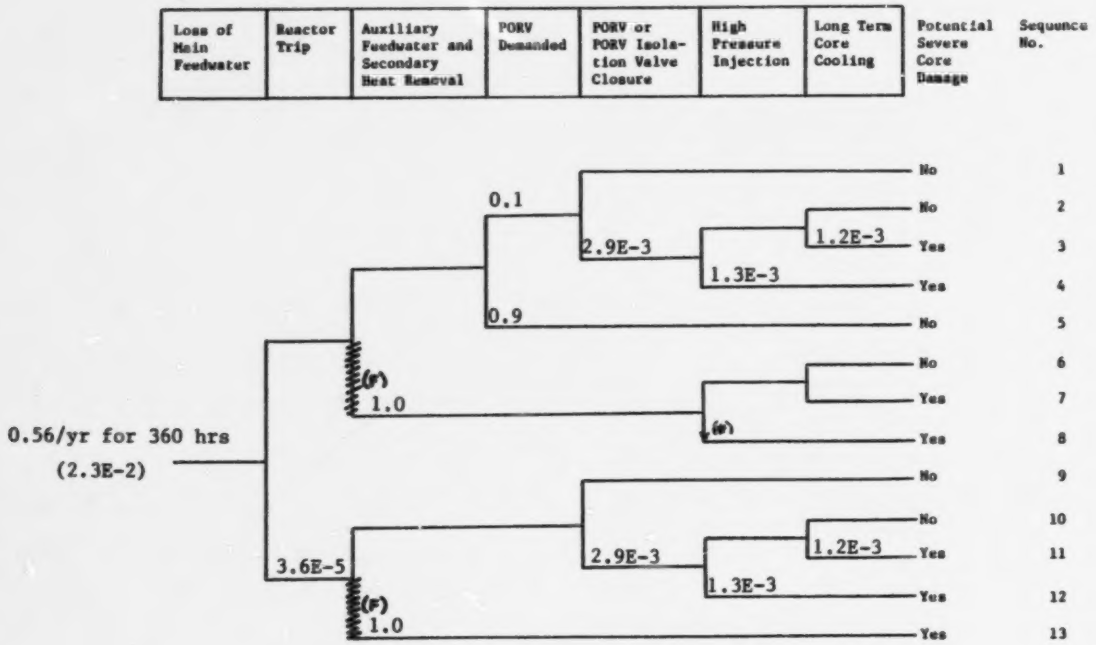
[redacted]


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 6.75 hrs (3.16E-5)
1.0
(D)
1.8E-2
(CF)
1.0
0.1
0.9
2.9E-3
(CD)1.3E-2
(CD)1.2E-2
(*)
1.0
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 3.2E-5 + addl. cont. (LOFW), 4.7E-6 = 3.6E-3 (SC = 44)

NSIC 89252 — Sequence of Interest for Failure of Diesel Generator to Start and Load When Two AFW Pumps Were Out of Service at Zion 2

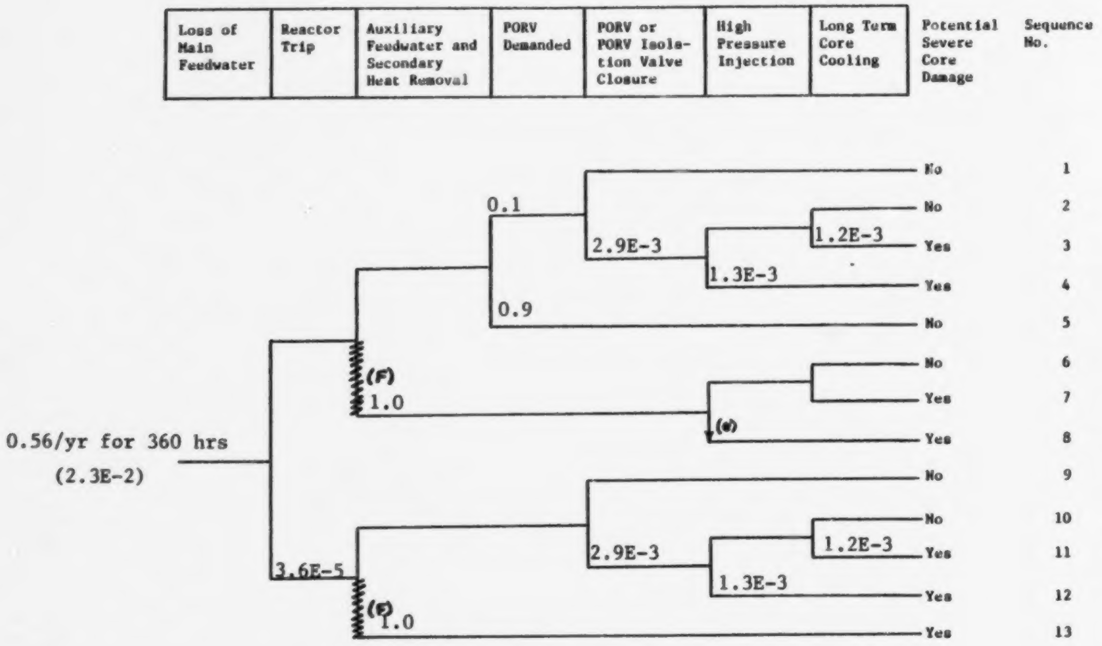
*Use of HPI following AFW failure not included in mitigating procedures.


Loss of Main Feedwater
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.56/yr for 360 hrs (2.3E-2)
0.1
0.9
2.9E-3
1.3E-3
1.2E-3
(F)
1.0
(*)
3.6E-5
2.9E-3
1.3E-3
1.2E-3
(F)
1.0
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

P = 2.3E-2 + addl. cont. (LOOP), 1.7E-3 = 2.5E-2 (SC = 16)

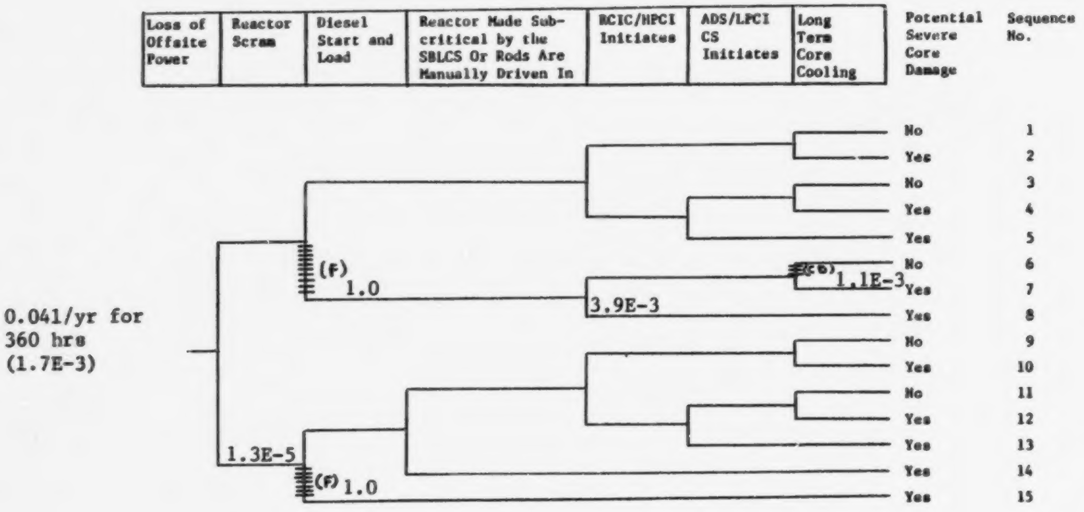
NSIC 90421 — Sequence of Interest for Auxiliary Feed Pump Suction Strainers Clogged at Point Beach 1 & 2
*Use of HPI following AFW failure not included in mitigation procedures.

[redacted]


Loss of Main Feedwater
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.56/yr for 360 hrs
(2.3E-2)
0.1
0.9
2.9E-3
1.3E-3
1.2E-3
(F)
1.0
(*)
3.6E-5
(F)
1.0
2.9E-3
1.3E-3
1.2E-3
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

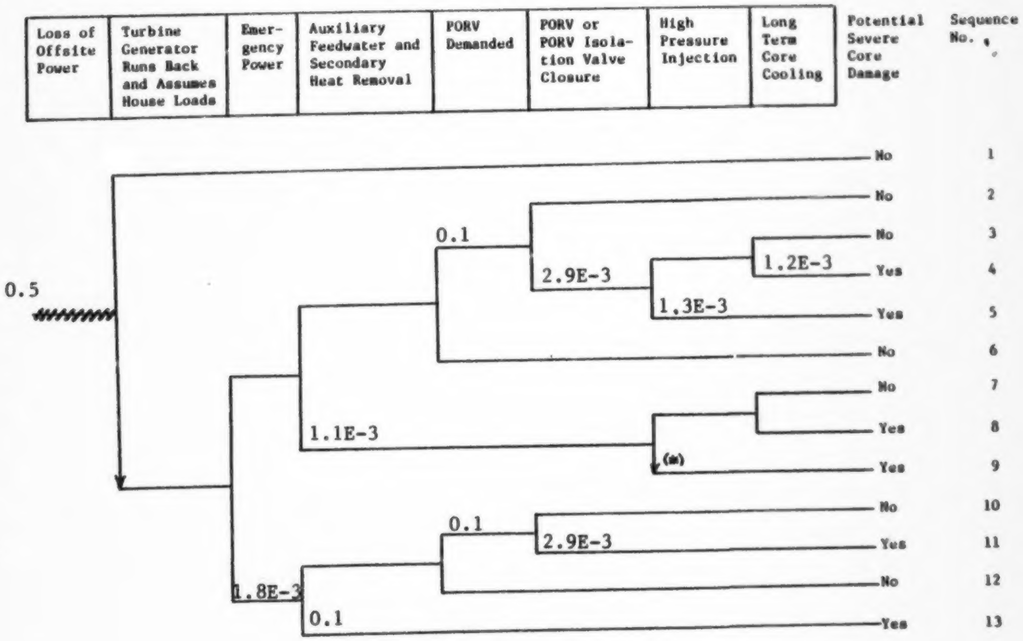
P = 2.3E-2 + addl. cont. (LOOP), 1.7E-3 = 2.5E-2 (SC = 16)

NSIC 91676 — Sequence of Interest for Malfunction of Auxiliary Feedwater Pumps at Turkey Point 3
***Use of HPI following AFW failure not included in mitigation procedures.**


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 360 hrs
(1.7E-3)
(F)
1.0
3.9E-3
(CC)
1.1E-3
1.3E-5
(F)
1.0
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

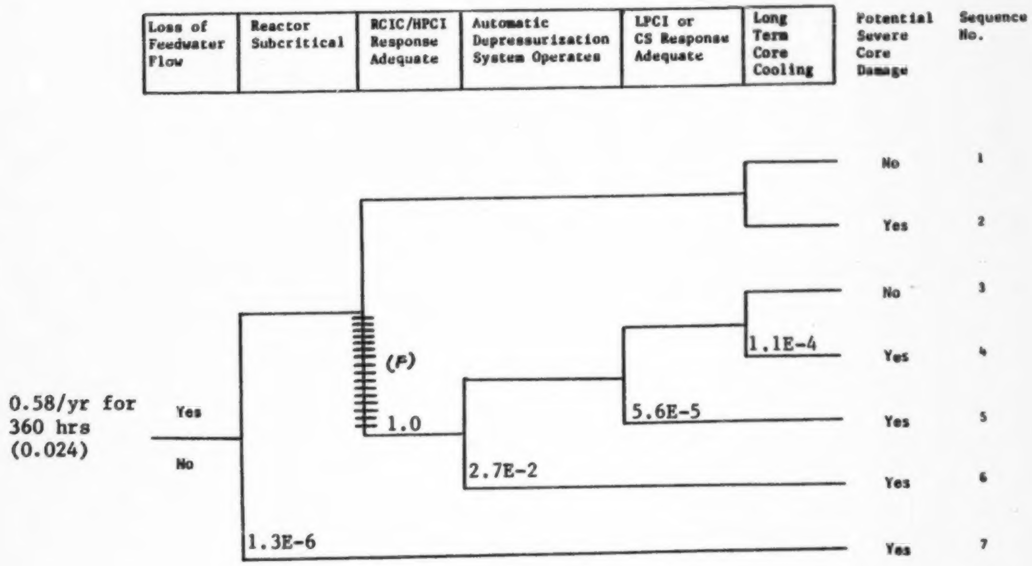
P = 7.8E-6 (SC = 51)

NSIC 93553 — Sequence of Interest of Two Diesel Generators Fail at Hatch 1


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
(*)
0.1
2.9E-3
1.8E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

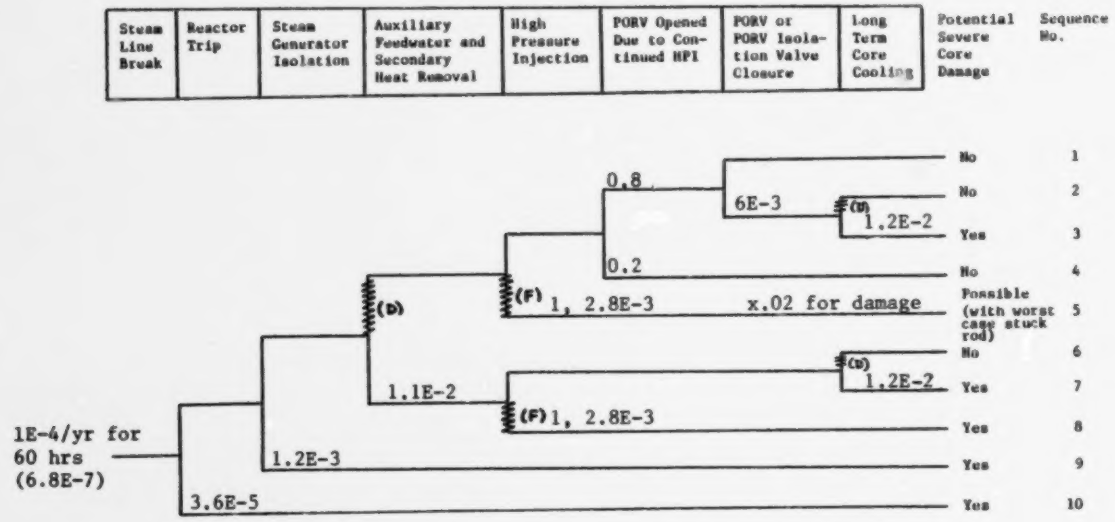
P = 6.4E-4 (SC = 32)

NSIC 93702 – Sequence of Interest for Two Unit Trip at Turkey Point 3 & 4
*Use of HPI following AFW failure not included in mitigation procedures.


Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.58/yr for 360 hrs (0.024)
Yes
No
(F)
1.0
1.1E-4
5.6E-5
2.7E-2
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

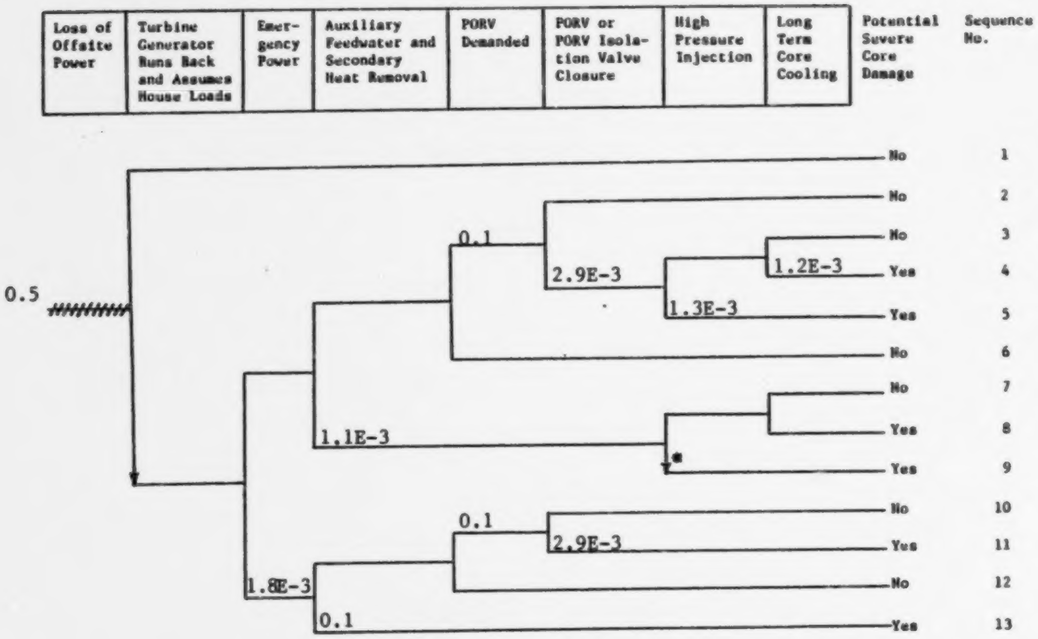
P = 6.4E-4 + addl. cont. (LOOP, LOCA, MSLB), 1.2E-4 = 7.6E-4 (SC = 31)

NSIC 95040 – Sequence of Interest for HPCI Injection Valves and RCIC Fail at Browns Ferry 2


Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.8
6E-3
(D)
1.2E-2
0.2
(D)
(F) 1, 2.8E-3
x.02 for damage
(D)
1.2E-2
1.1E-2
(F) 1, 2.8E-3
1E-4/yr for 60 hrs (6.8E-7)
1.2E-3
3.6E-5
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

P = 2.1E-8 + addl. cont. (LOFW, LOOP), 2.4E-4 = 2.4E-4 (SC = 36)

NSIC 97107 — Sequence of Interest for Boron Injection Tank Valve Failures at Zion 2


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
*
0.1
2.9E-3
1.8E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

NSIC 97578 — Sequence of Interest for Loss of Offsite Power During SIS Testing at Palisades

*Not included in mitigation sequence.

P = 6.4E-4 x prob. of occurring at power (0.75) = 4.8E-4 (SC = 33)

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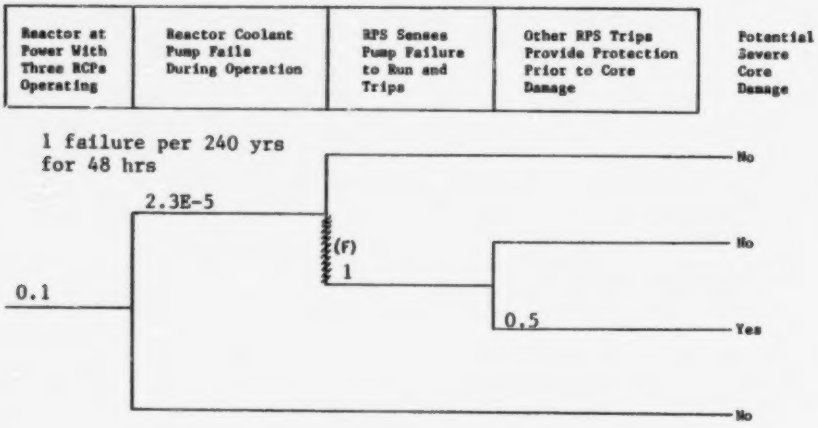
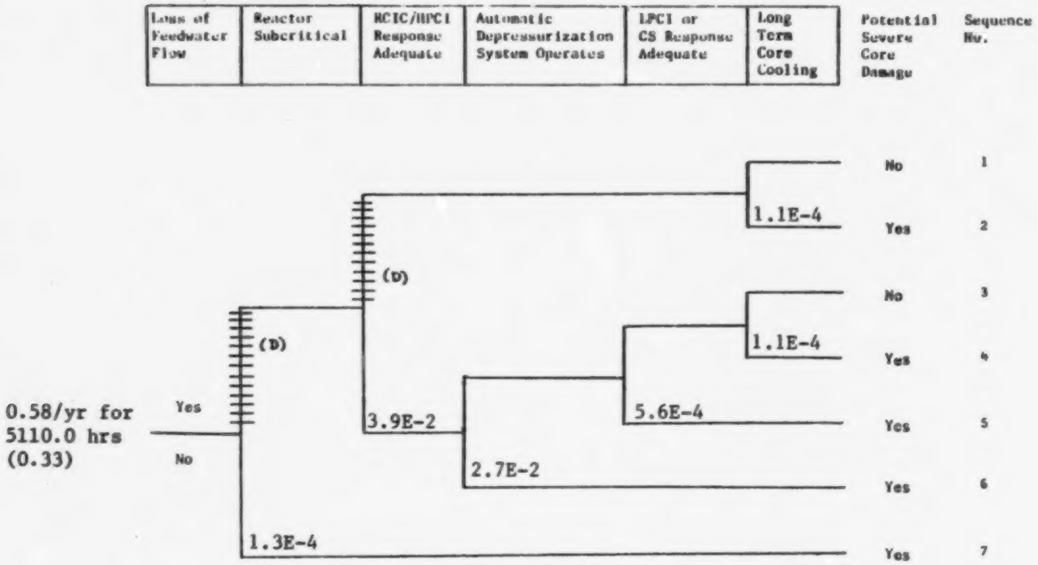
BEST DOCUMENT AVAILABLE


Reactor at Power With Three RCPs Operating
Reactor Coolant Pump Fails During Operation
RPS Senses Pump Failure to Run and Trips
Other RPS Trips Provide Protection Prior to Core Damage
Potential Severe Core Damage
1 failure per 240 yrs for 48 hrs
0.1
2.3E-5
(F)
1
0.5
No
No
Yes
No

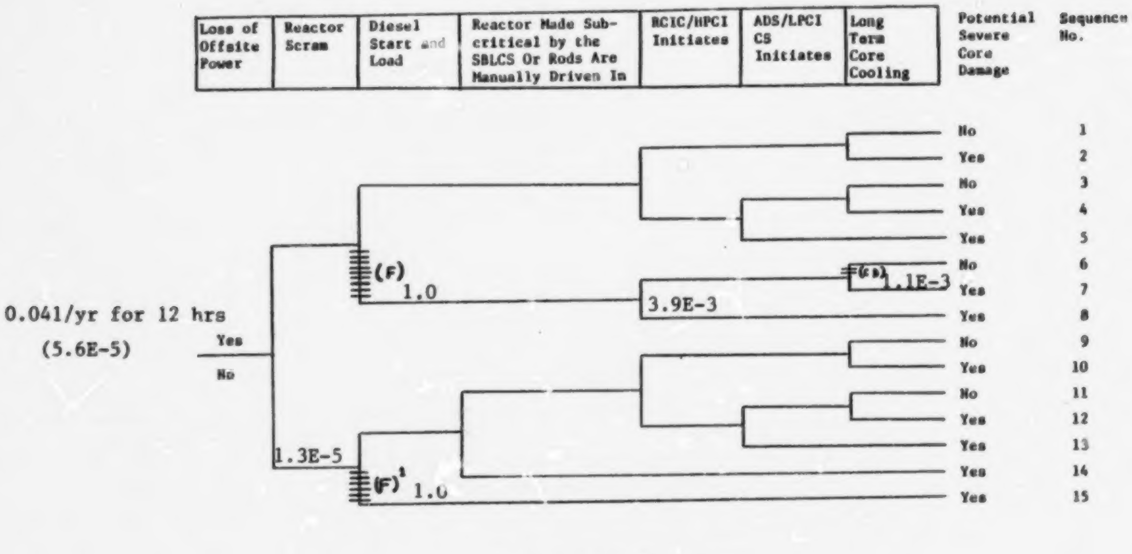
P = 1.2E-6· (SC = 59)

NSIC 97779 — Sequence of Interest for Reactor Coolant Pump Undervoltage/Overpower Monitoring Relays Fail to Function at Arkansas Nuclear 1


Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.58/yr for 5110.0 hrs (0.33)
Yes
No
(D)
(D)
1.1E-4
1.1E-4
5.6E-4
3.9E-2
2.7E-2
1.3E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 4.5E-4 (SC = 34)

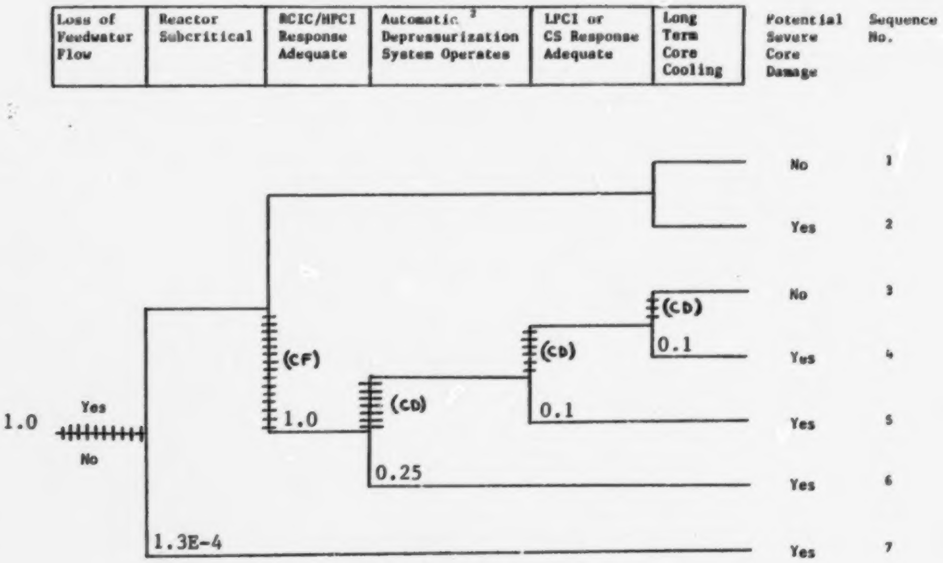
NSIC 100415 - Sequence of Interest for All Drywell Pressure Switches Found Isolated at Fitzpatrick


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 12 hrs
(5.6E-5)
Yes
No
(F)
1.0
3.9E-3
(CD)
1.1E-3
1.3E-5
(F)¹
1.0
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 2.6E-7 (SC = 66)

NSIC 101078 — Sequence of Interest for a Diesel Generator Fire at Fitzpatrick

[1] Since diesel generator B was operable the operator could have had either the control rod drive pumps or the standby liquid control system.

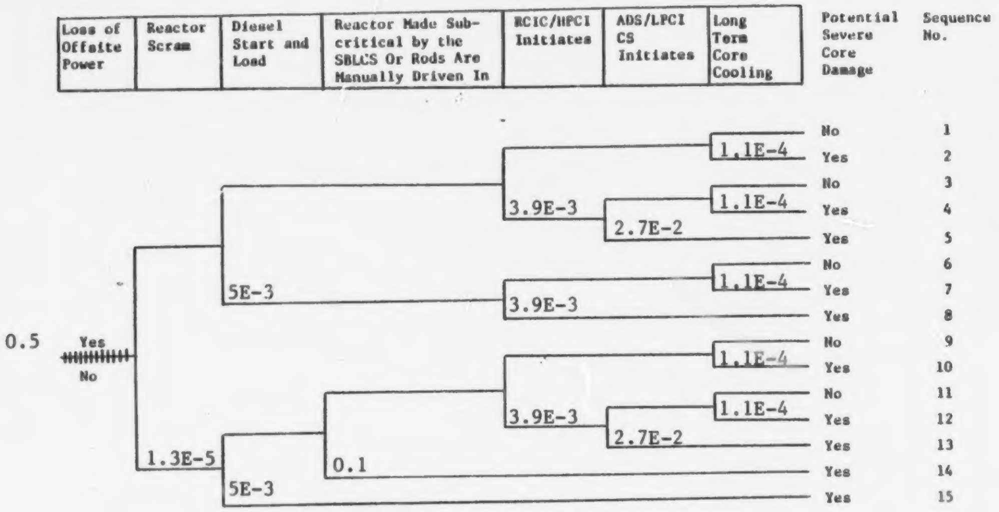

Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic² Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
Yes
No
(CF)
1.0
(CD)
0.25
(CD)
0.1
(CD)
0.1
1.3E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 0.39 (SC = 4)

NSIC 101444 — Sequence of Interest of Cable Tray Fire at Browns Ferry 1

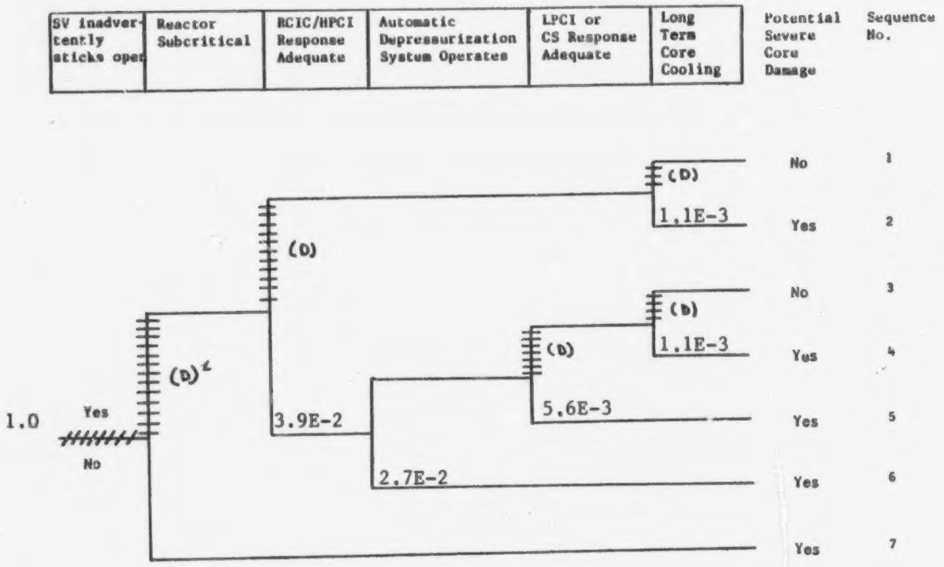
[1] Nonstandard techniques could have been used to make RCIC operable.

[2] The depressurization was manually initiated.


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
Yes
No
1.1E-4
3.9E-3
1.1E-4
2.7E-2
5E-3
1.1E-4
3.9E-3
1.1E-4
1.1E-4
3.9E-3
2.7E-2
1.3E-5
0.1
5E-3
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 1.2E-4 (SC = 39)

NSIC 102146 — Sequence of Interest for Loss of Offsite Power at Brunswick 2

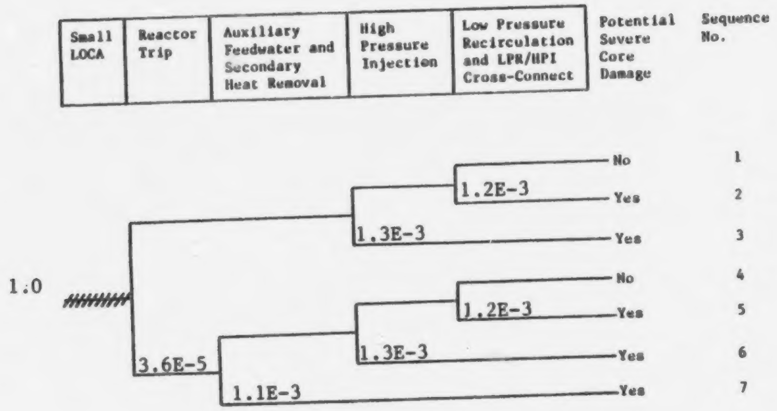

SV inadvertently sticks open
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
Yes
No
(D)[1]
(D)
(D)
1.1E-3
3.9E-2
(D)
(D)
1.1E-3
5.6E-3
2.7E-2
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 2.4E-3 (SC = 26)

NSIC 103002 — Sequence of Interest for Multiple Valve Failures and RCIC Inoperable at Brunswick 2

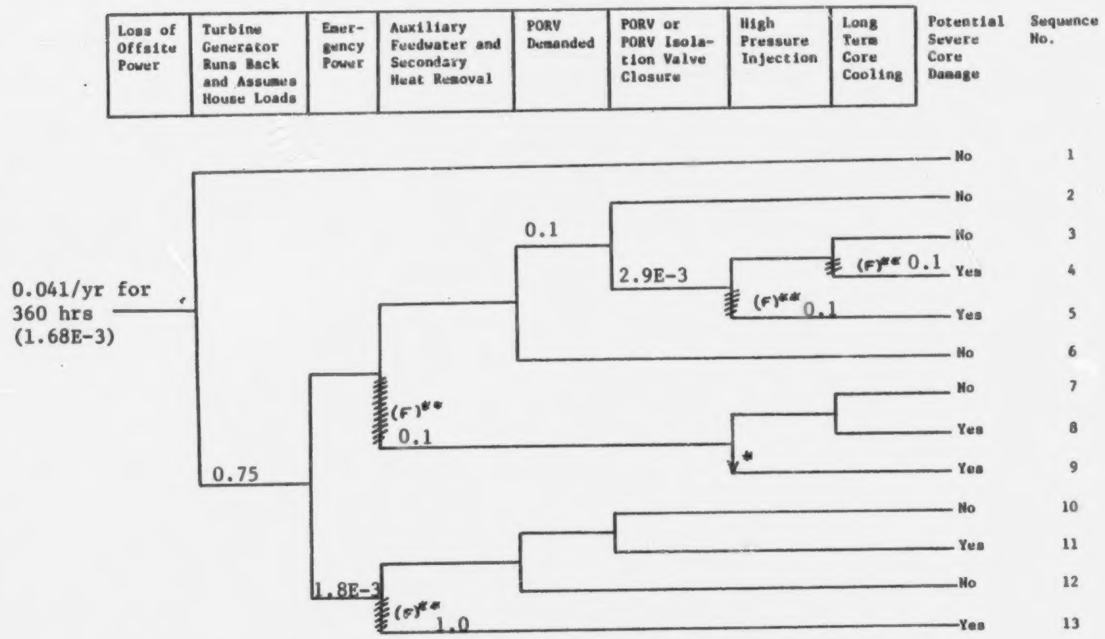
---

[1] The operator failed to manually scram the reactor as emergency instruction requires.


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
1.0
1.2E-3
1.3E-3
1.2E-3
1.3E-3
3.6E-5
1.1E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 2.5E-3 (SC = 26)

NSIC 103077 – Sequence of Interest for Reactor Coolant Pump Seal System Fails at Robinson 2

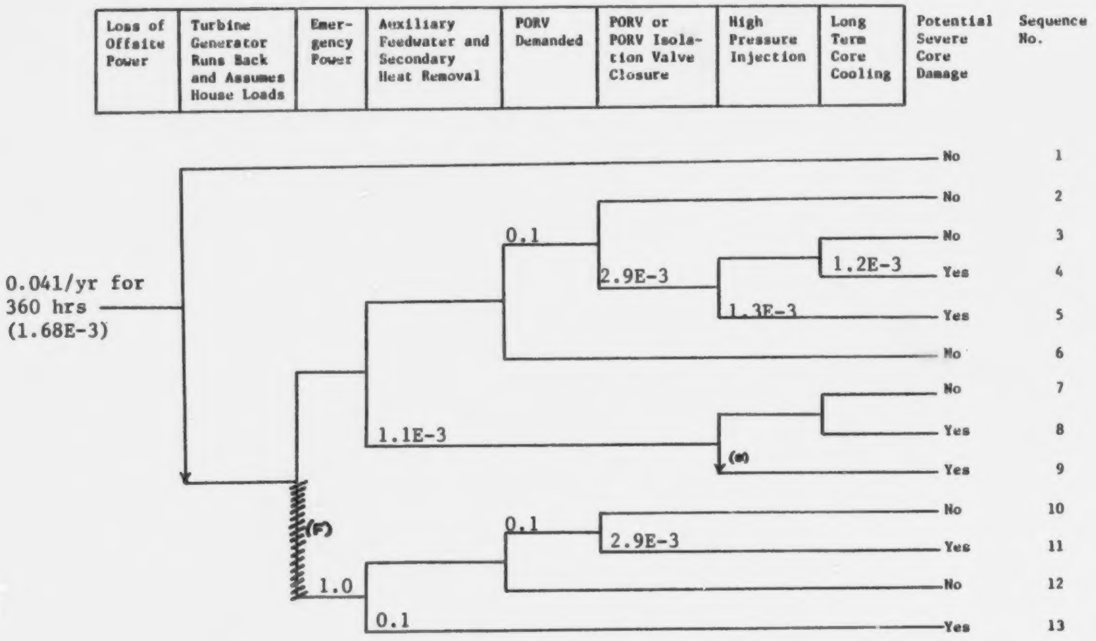

Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 360 hrs (1.68E-3)
0.1
2.9E-3
(F)** 0.1
(F)** 0.1
(F)** 0.1
*
0.75
1.8E-3
(F)** 1.0
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1.28E-4 x prob. of occurring at power (0.75) = 9.6E-5 (SC = 40)

NSIC 103111 – Sequence of Interest for Condenser Circulating Water Valves Failure to Close at Oconee 3

*not included in mitigation procedures.

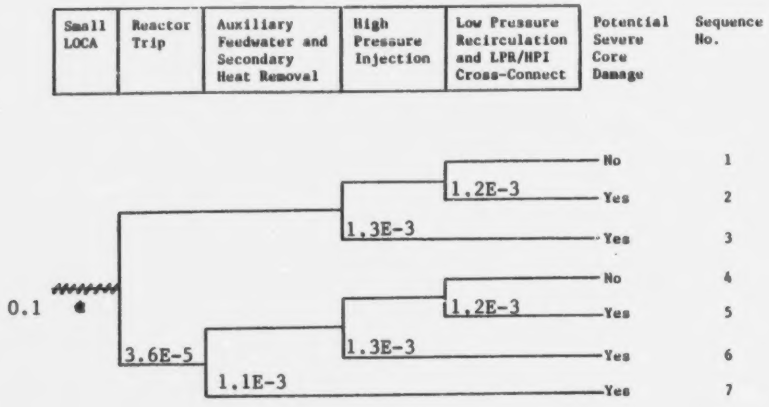
**success requires manual operation of emergency discharge valves to establish circulating water flow.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 360 hrs (1.68E-3)
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
(*)
(F)
0.1
2.9E-3
1.0
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1.66E-4 x prob. of occurring at power (0.75) = 1.25E-4 (SC = 39)

NSIC 103207 — Sequence of Interest for Diesel Generator Breaker and Bus Stripping Relay Malfunction at Turkey Point 4

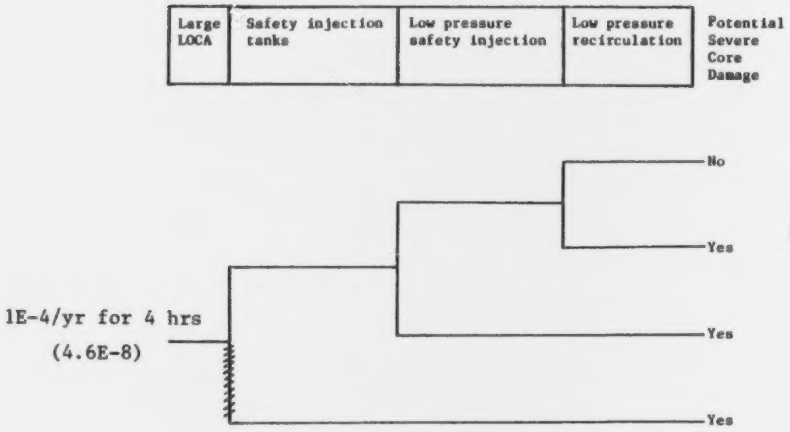
*use of HPI following AFW failure not included in mitigation procedures.


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
0.1
*
1.2E-3
1.3E-3
1.2E-3
1.3E-3
3.6E-5
1.1E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 2.5E-4 (SC = 36)

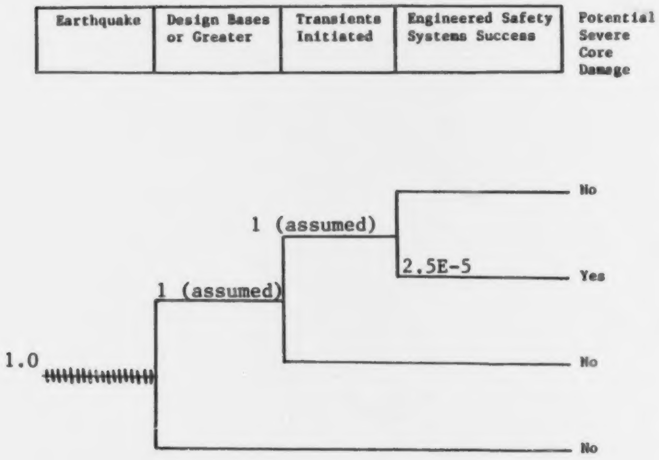
NSIC 103892 — Sequence of Interest for Excessive Cooldown Rate at Oconee 3

*failure requires operator error in failing to close the PORV isolation valve.


Large LOCA
Safety injection tanks
Low pressure safety injection
Low pressure recirculation
Potential Severe Core Damage
No
Yes
Yes
Yes
1E-4/yr for 4 hrs
(4.6E-8)

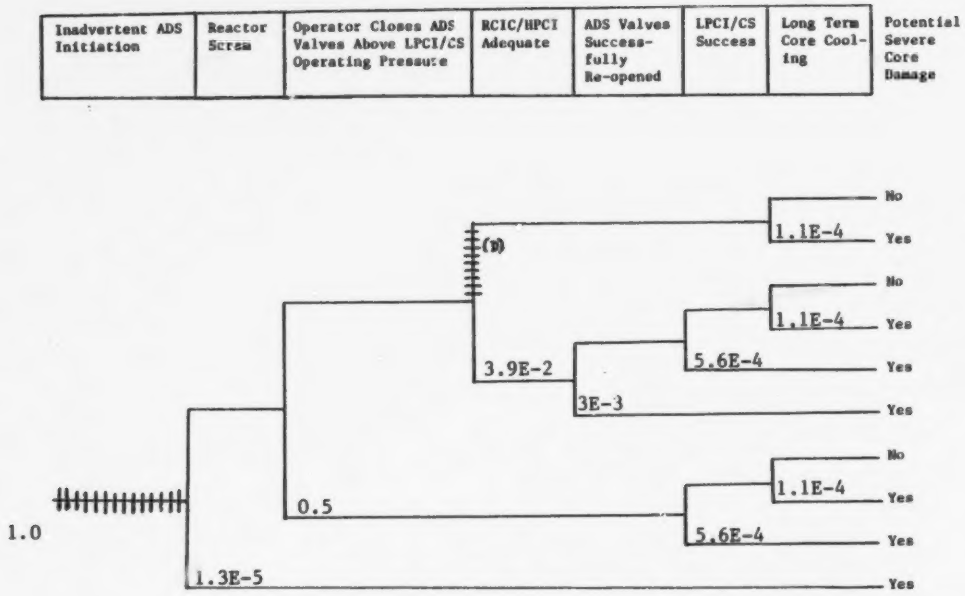
P = 4.6E-8 x prob. of occurring at power (0.75) = 3.5E-8 (SC = 74)

NSIC 104087 – Sequence of Interest for Safety Injection Tank Isolation Valves Closed at Maine Yankee


Earthquake
Design Bases or Greater
Transients Initiated
Engineered Safety Systems Success
Potential Severe Core Damage
1 (assumed)
2.5E-5
1 (assumed)
1.0
No
Yes
No
No

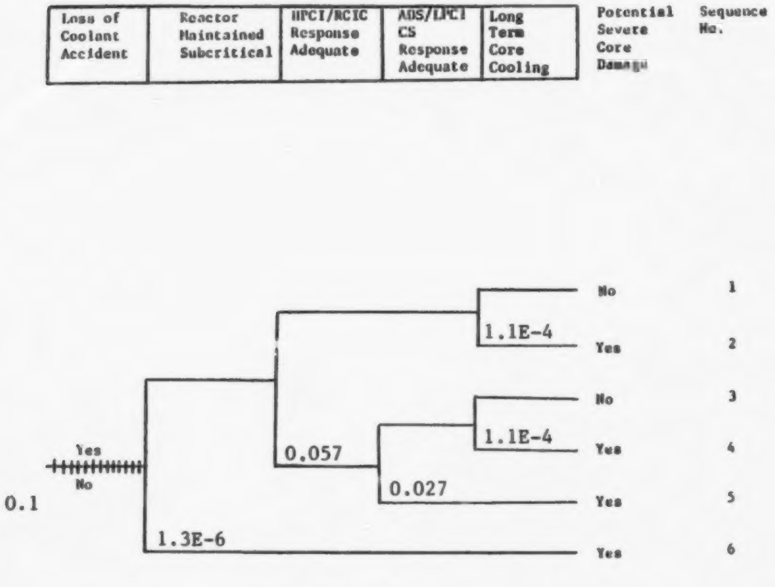
P = 2.5E-5 (SC = 46)

NSIC 104379 – Sequence of Interest for Earthquake Occurrence at Humboldt Bay


Inadvertent ADS Initiation
Reactor Scram
Operator Closes ADS Valves Above LPCI/CS Operating Pressure
RCIC/HPCI Adequate
ADS Valves Successfully Re-opened
LPCI/CS Success
Long Term Core Cooling
Potential Severe Core Damage
1.0
(D)
1.1E-4
3.9E-2
1.1E-4
5.6E-4
3E-3
0.5
1.1E-4
5.6E-4
1.3E-5
No
Yes
No
Yes
Yes
Yes
No
Yes
Yes
Yes

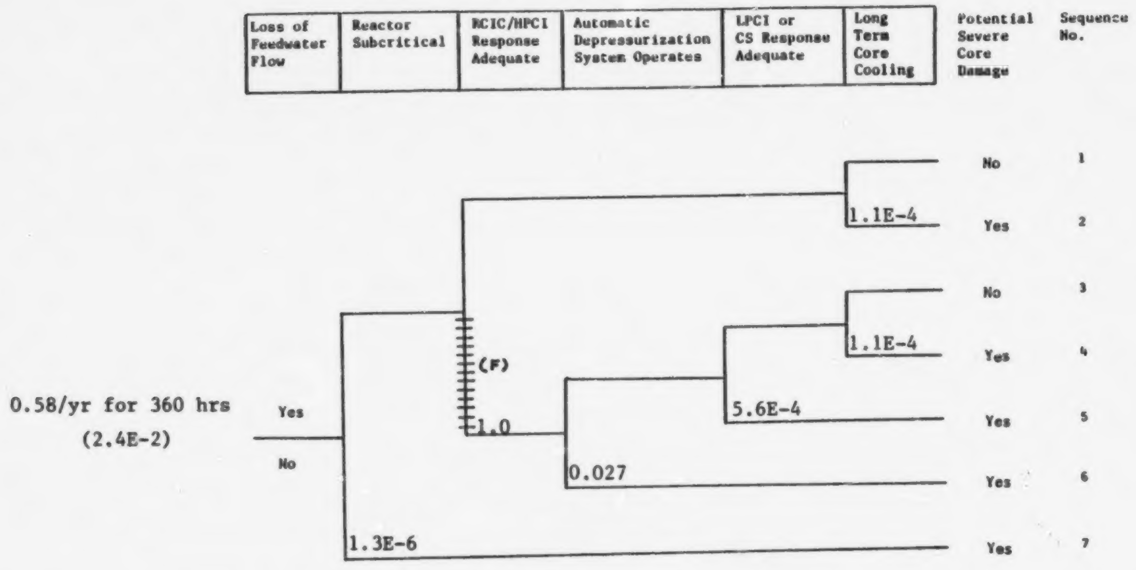
P = 4.7E-4 (SC = 33)

NSIC 104817 — Sequence of Interest for all ADS Valves Opened Inadvertently at Hatch 1


Loss of Coolant Accident
Reactor Maintained Subcritical
HPCI/RCIC Response Adequate
ADS/LPCI CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.1
Yes
No
1.1E-4
0.057
1.1E-4
0.027
1.3E-6
No
Yes
No
Yes
Yes
Yes
1
2
3
4
5
6

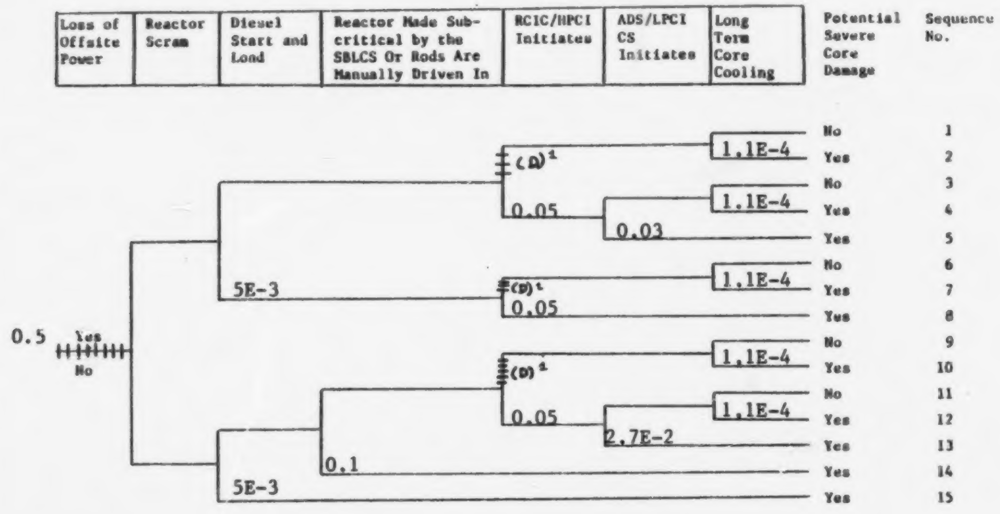
P = 1.7E-4 (SC = 38)

NSIC 105540 — Sequence of Interest for Low Flow Feedwater Line Severed at 6x4 Reducer at Quad Cities 2


Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.58/yr for 360 hrs
(2.4E-2)
Yes
No
(F)
1.0
1.1E-4
1.1E-4
5.6E-4
0.027
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 6.6E-4 (SC = 32)

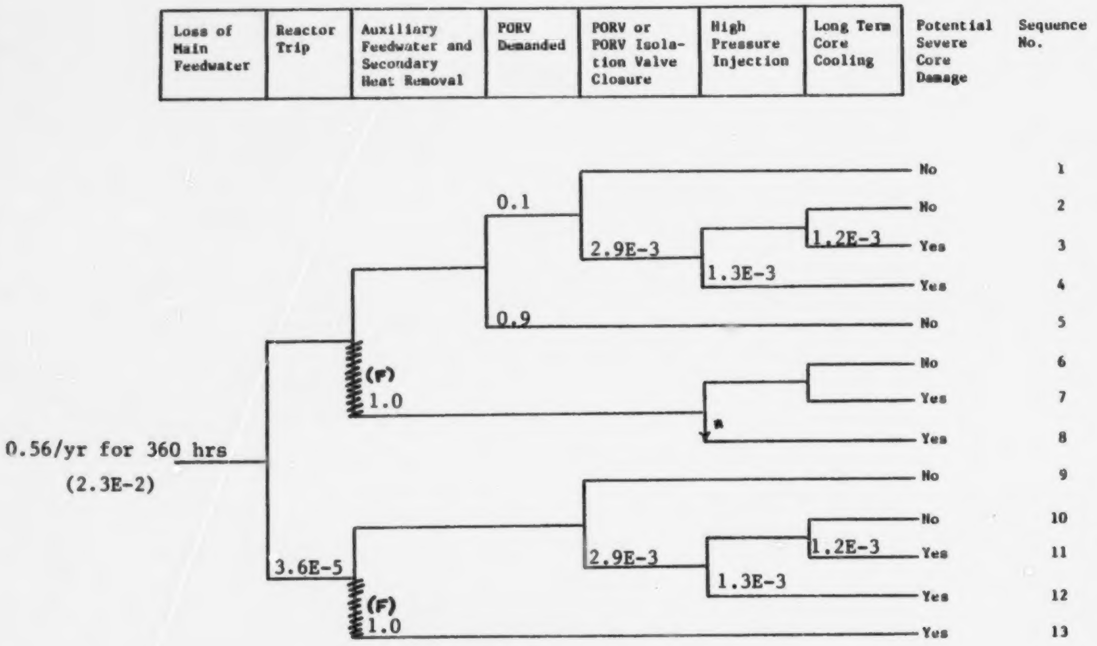
NSIC 106333 – Sequence of Interest for HPCI Found Inoperable at Quad Cities 2


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
Yes
No
(D)1
(D)1
(D)1
0.05
0.05
0.05
0.03
2.7E-2
5E-3
0.1
5E-3
1.1E-4
1.1E-4
1.1E-4
1.1E-4
1.1E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 9.3E-4 (SC = 30)

NSIC 106616 – Sequence of Interst for Loss of Offsite Power and a Relief Valve Sticks Open at Pilgrim 1

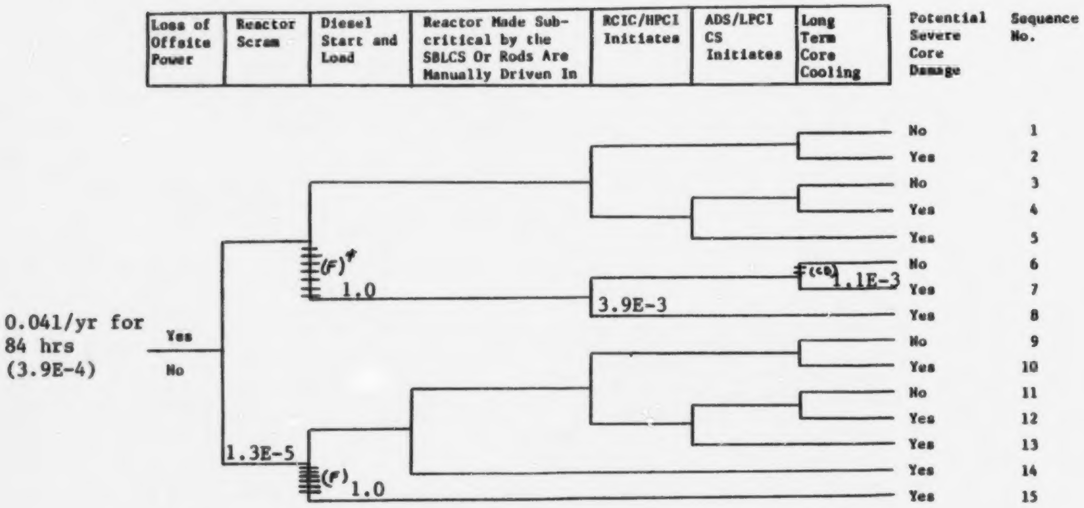
1 A relief valve stuck open.


Loss of Main Feedwater
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.56/yr for 360 hrs
(2.3E-2)
0.1
2.9E-3
1.2E-3
1.3E-3
0.9
(F)
1.0
*
3.6E-5
2.9E-3
1.2E-3
1.3E-3
(F)
1.0
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

P = 2.3E-2 (SC = 16)

NSIC 108078 – Sequence of Interest for Auxiliary Feedwater Pump Flows Restricted at Kewaunee

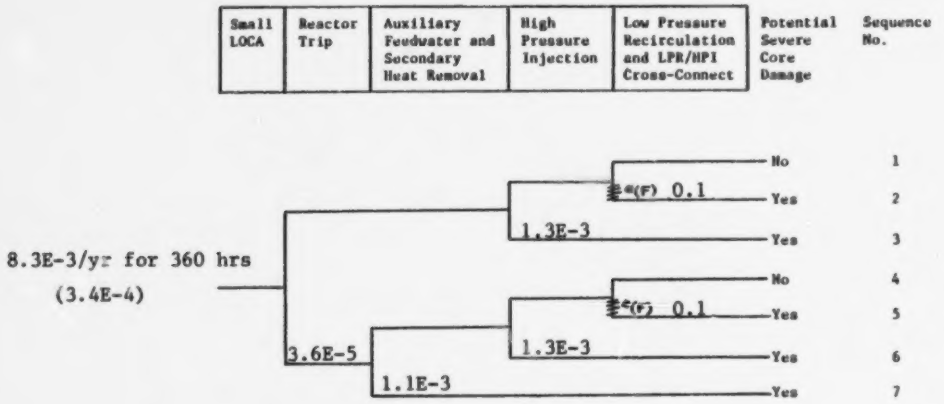
*not included in mitigation procedures


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 84 hrs (3.9E-4)
Yes
No
(F)*
1.0
3.9E-3
(CD)
1.1E-3
1.3E-5
(F)
1.0
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 1.8E-6 + addl. cont. (LOFW, LOCA, MSLB), 3.4E-5 = 3.6E-5 (SC = 44)

NSIC 108869 – Sequence of Interest for Two Diesel Generators Fail to Start at Hatch 1

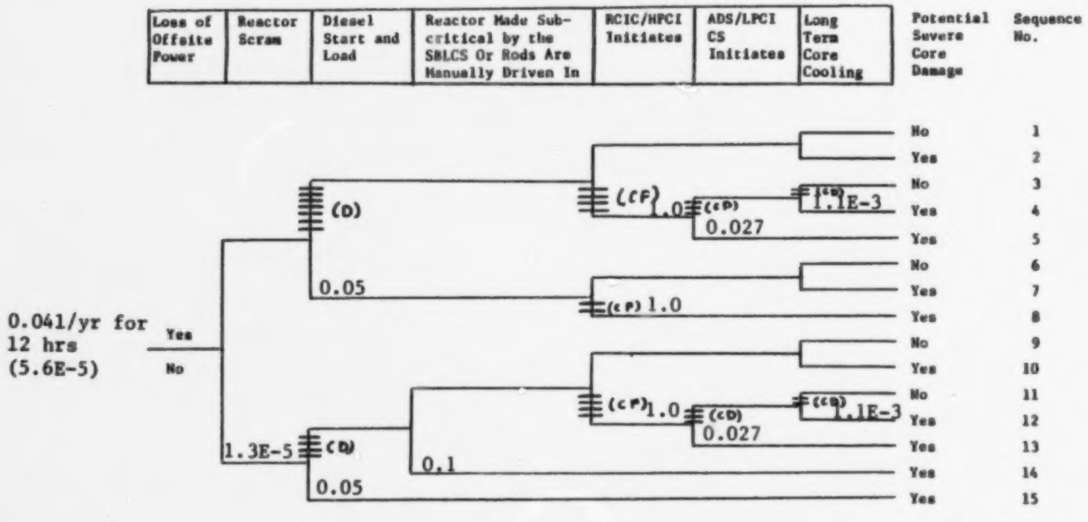
*Proper load shedding by the operator may result in a degraded state of the emergency power system.


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
8.3E-3/yr for 360 hrs
(3.4E-4)
*(F) 0.1
1.3E-3
*(F) 0.1
1.3E-3
3.6E-5
1.1E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 3.4E-5 (SC = 45)

NSIC 109295 — Sequence of Interest for Failure to BWST Level Indication at Oconee 1

*success requires the operator to switch to recirculation without BWST indication after sufficient water has been injected for LP pump NPSH and before the BWST is emptied, and without level indication.


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Sub-critical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 12 hrs
(5.6E-5)
Yes
No
(D)
0.05
(CF) 1.0
(CD) 0.027
(CD) 1.1E-3
(CF) 1.0
1.3E-5
(D)
0.1
0.05
(CF) 1.0
(CD) 0.027
(CD) 1.1E-3
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 4.38E-6 (SC = 54)

NSIC 112309 — Sequence of Interest of Gas Turbine Becomes Inoperable at Millstone 1

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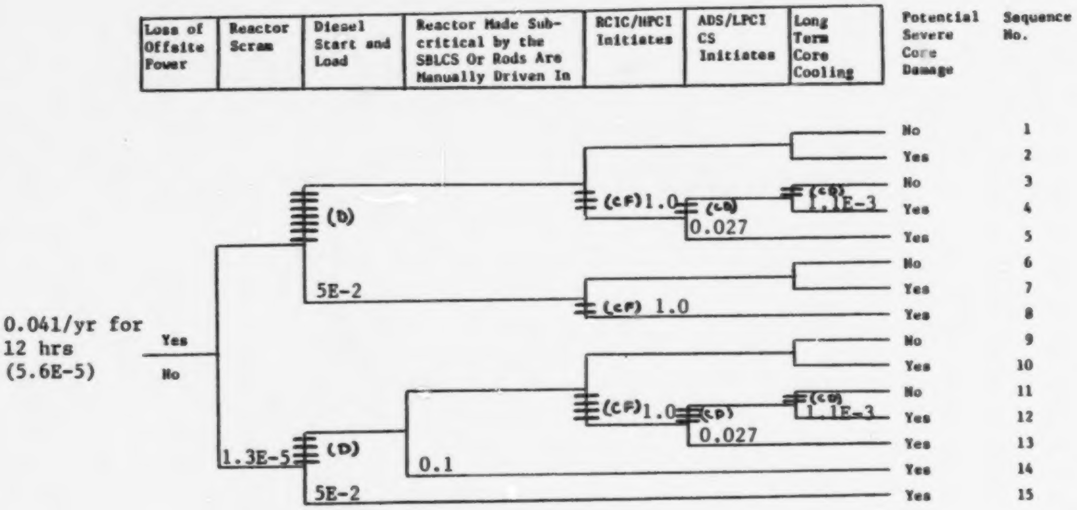
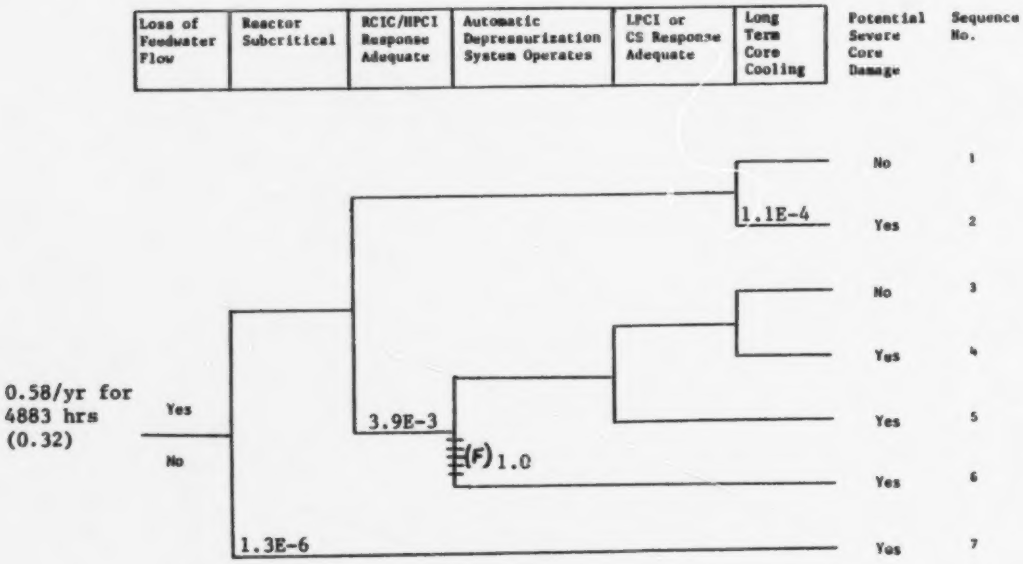

Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 12 hrs (5.6E-5)
Yes
No
(D)
5E-2
(CF) 1.0
(CD)
1.1E-3
0.027
(CF) 1.0
1.3E-5
(D)
0.1
5E-2
(CF) 1.0
(CD)
0.027
(CD)
1.1E-3
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 4.21E-6 (SC = 54)

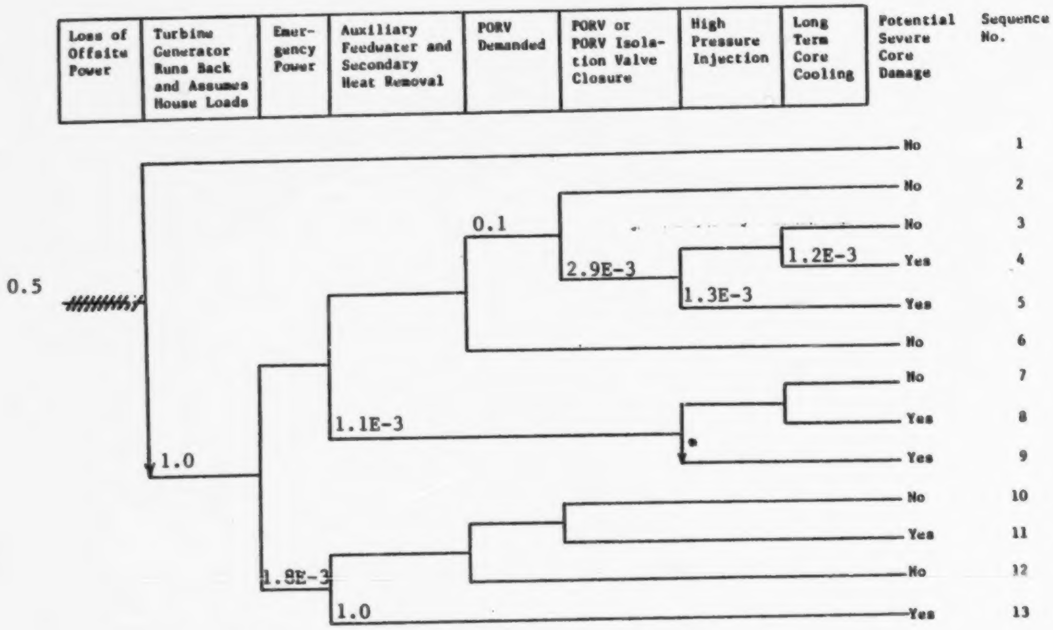
NSIC 112310 – Sequence of Interest for Gas Turbine Fails to Achieve Rated Speed at Millstone 1


Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.58/yr for 4883 hrs (0.32)
Yes
No
1.1E-4
3.9E-3
(F) 1.0
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 1.3E-3 + addl. cont. (LOOP, LOCA, MSLB), 8E-4 = 2.1E-3
x prob. of occurring at power (0.75) = 1.6E-3 (SC = 28)

NSIC 115670 – Sequence of Interest for Main Steam Relief Valve Fails to Operate at Vermont Yankee

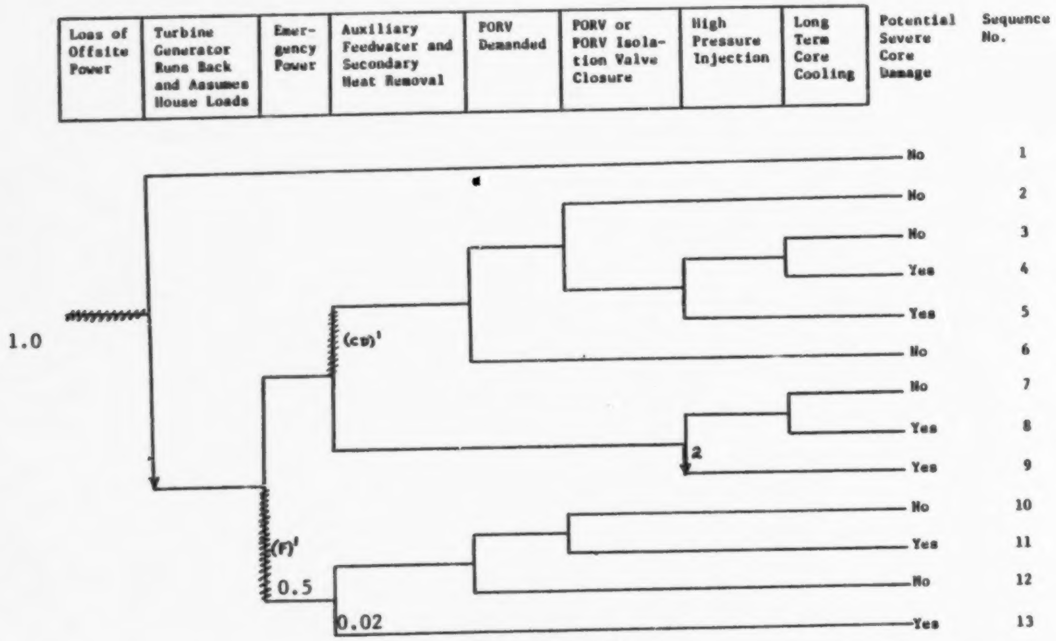
BEST DOCUMENT AVAILABLE


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
1.8E-3
1.0
*
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1.45E-3 x prob. of occurring at power (0.75) = 1.1E-3 (SC = 29)

NSIC 115875 – Sequence of Interest for Total Loss of 115kv Station Power Occurs at Connecticut Yankee

[*] not part of mitigation procedure

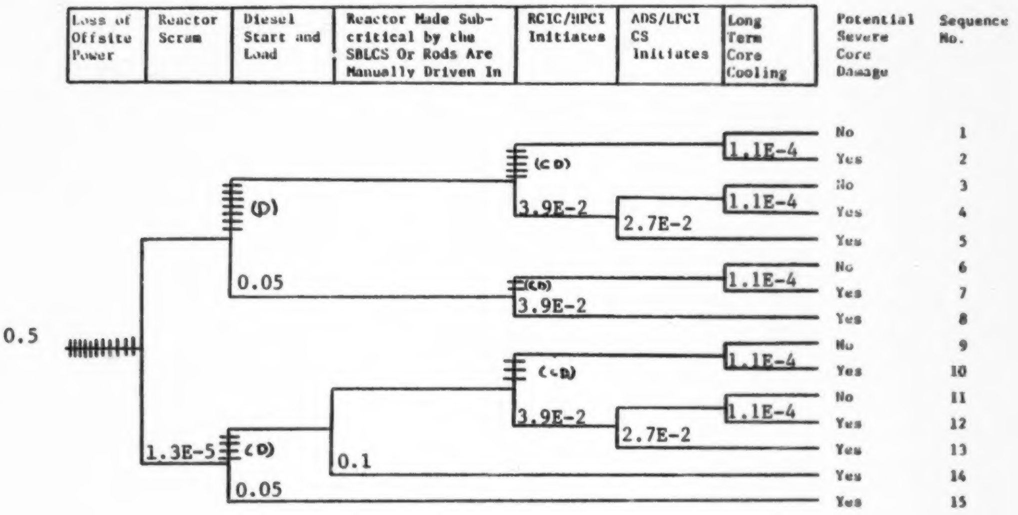

Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
(CV)¹
(F)¹
0.5
0.02
2
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1E-2 (SC = 20)

NSIC 116212 – Sequence of Interest for Inadvertent Load Shedding on Safety-Related Buses at Millstone 2

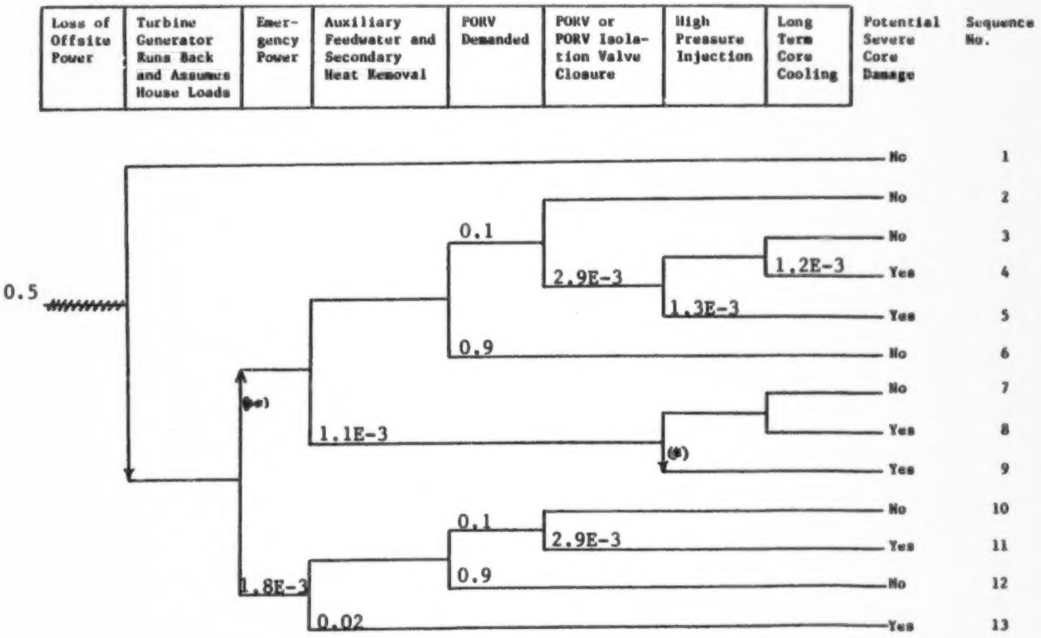
[1] Success requies immediate operator action to reset undervoltage trip setpoints and reload safety-related loads.

[2] Operating procedures did not provide for use of HPI for core cooling


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
(D)
0.05
(CD)
3.9E-2
2.7E-2
1.1E-4
1.1E-4
(CD)
3.9E-2
1.1E-4
1.3E-5
(CD)
0.1
0.05
(CD)
3.9E-2
2.7E-2
1.1E-4
1.1E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 0.0016 (SC = 28)

NSIC 116780 — Sequence of Interest of Gas Turbine Becomes Unavailable at Millstone 1


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
0.1
2.9E-3
1.2E-3
1.3E-3
0.9
(**)
1.1E-3
(*)
0.1
2.9E-3
0.9
1.8E-3
0.02
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 5.7E-4 (SC = 32)

NSIC 117944 — Sequence of Interest for Offsite Power Lost at Millstone 2

*Use of HPI after AFW failure not included in mitigation procedures.

**diesel generators running but not loaded

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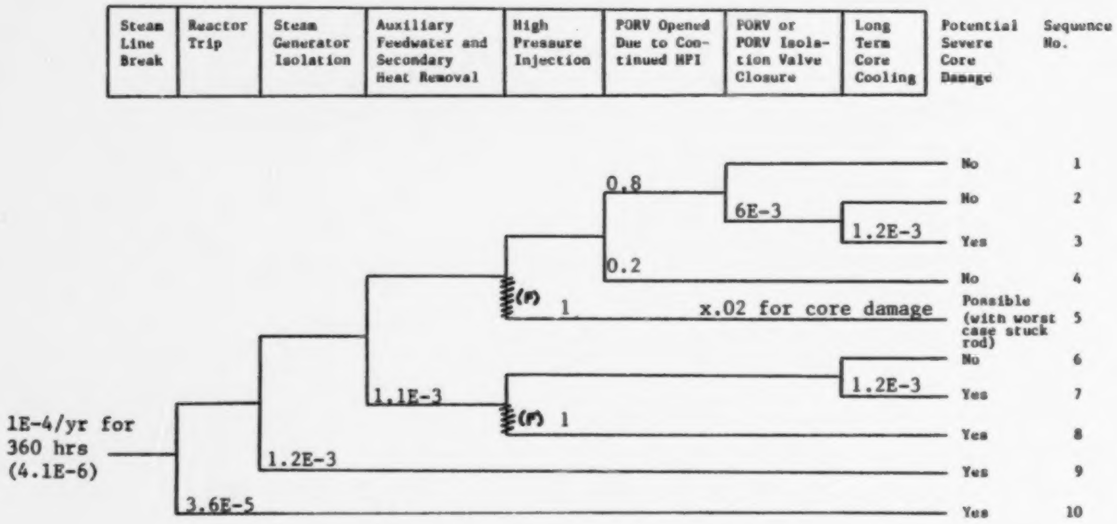
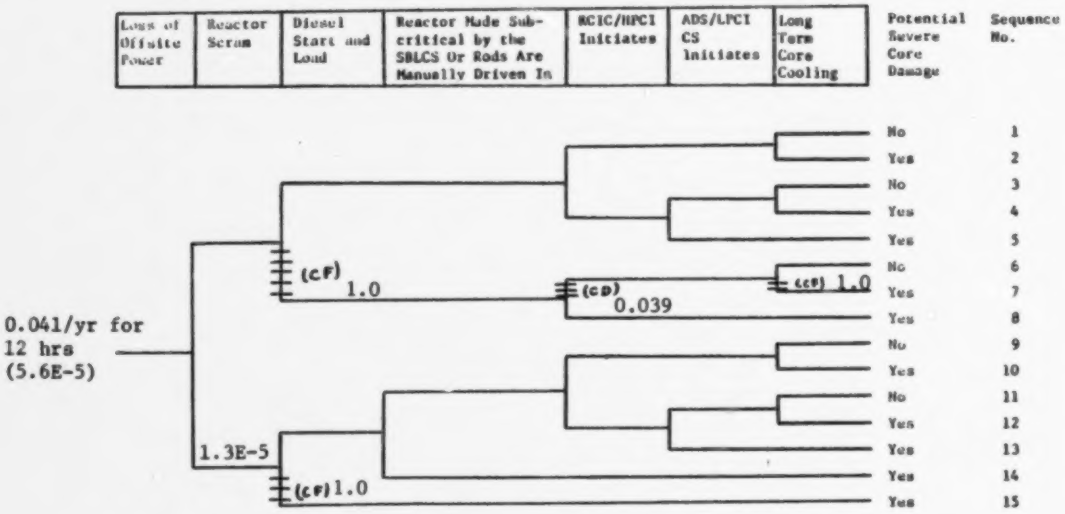
156

[redacted]


Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1E-4/yr for 360 hrs (4.1E-6)
0.8
6E-3
1.2E-3
0.2
(F) 1
x.02 for core damage
1.1E-3
1.2E-3
(F) 1
1.2E-3
3.6E-5
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

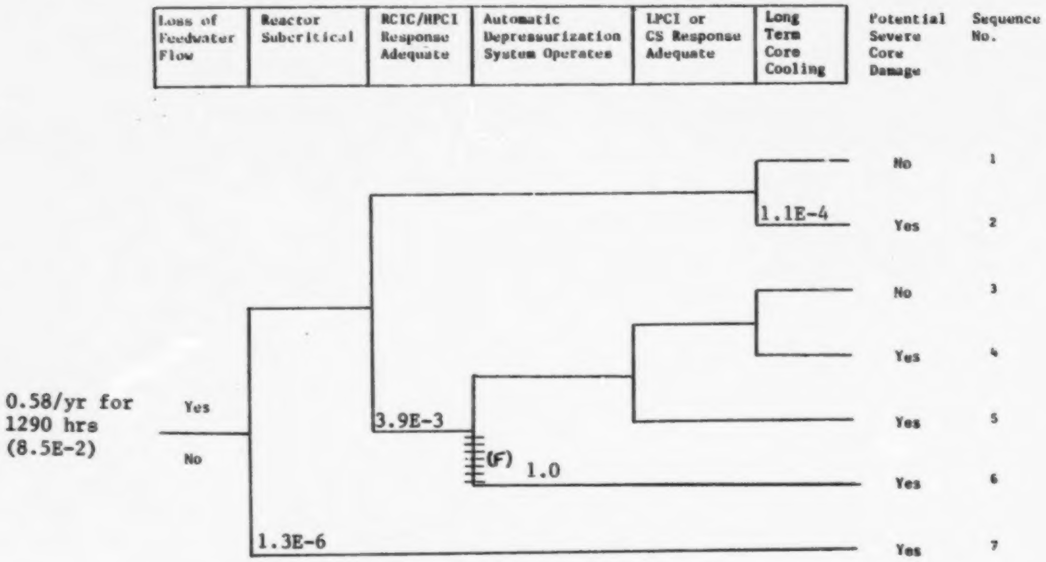
P = 7.69E-8 x prob. of occurring at power (0.75) = 5.8E-8 (SC = 72)

NSIC 120207 — Sequence of Interest for Failure of Both Charging Pump Suction Valves from RWST to Open at Trojan


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 12 hrs (5.6E-5)
(CF) 1.0
(CD) 0.039
(CF) 1.0
1.3E-5
(CF) 1.0
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

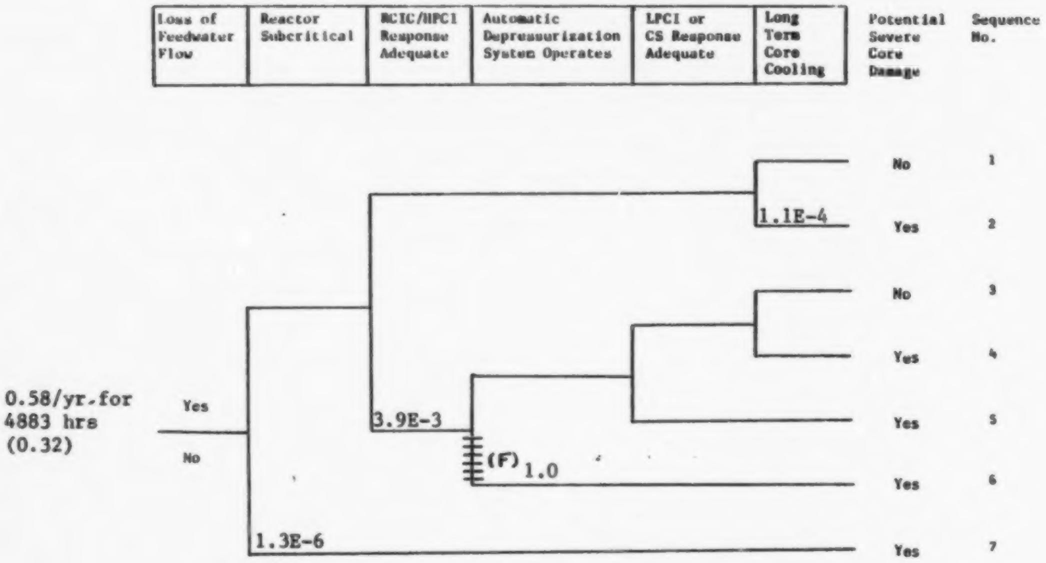
P = 5.8E-5 + addl. cont. (LOFW, LOCA, MSLB), 8.5E-4 = 9.1E-4 (SC = 30)

NSIC 120293 — Sequence of Interest of Plant Service Water Strainers Plug at Hatch 1


Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.58/yr for 1290 hrs (8.5E-2)
Yes
No
1.1E-4
3.9E-3
(F)
1.0
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

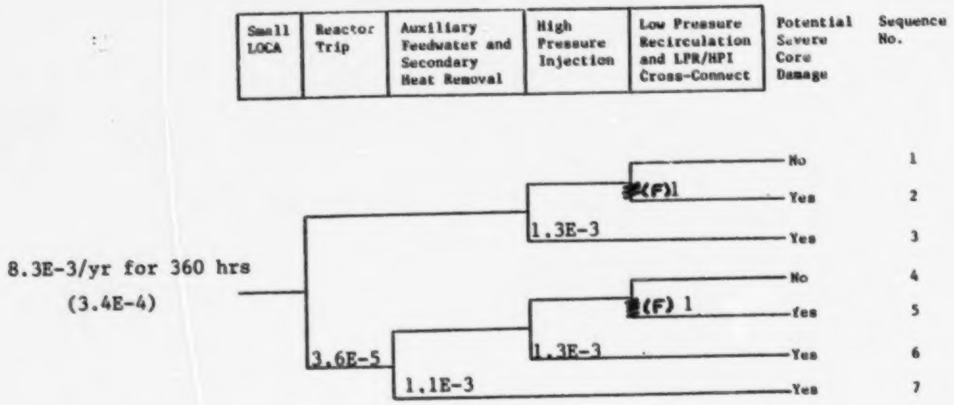
P = 3.4E-4 + addl. cont. (LOOP, LOCA, MSLB), 2.1E-4 = 5.5E-4 (SC = 33)

NSIC 120439 - Sequence of Interest for Two Electromatic Relief Valves Fail at Quad Cities 1


Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.58/yr.for 4883 hrs (0.32)
Yes
No
1.1E-4
3.9E-3
(F)
1.0
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

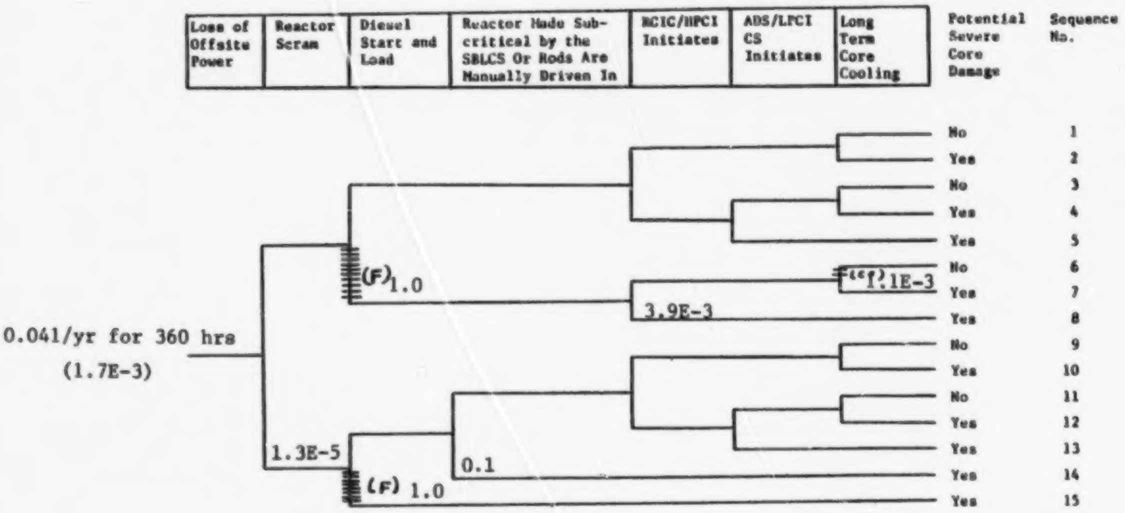
P = 1.3E-3 + addl. cont. (LOOP, LOCA, MSLB), 8E-4 = 2.1E-3
x prob. of occurring at power (0.75) = 1.6E-3 (SC = 28)

NSIC 120443 - Sequence of Interest for Two Electromatic Relief Valves Fail at Quad Cities 2


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
8.3E-3/yr for 360 hrs
(3.4E-4)
3.6E-5
1.1E-3
1.3E-3
(F) 1
1.3E-3
(F) 1
No
Yes
Yes
No
Yes
Yes
Yes
1
2
3
4
5
6
7

P = 3.4E-4 + addl. cont. (LOFW), 3.2E-5 = 3.7E-4 x
prob. of occurring at power (0.75) = 2.8E-4 (SC = 35)

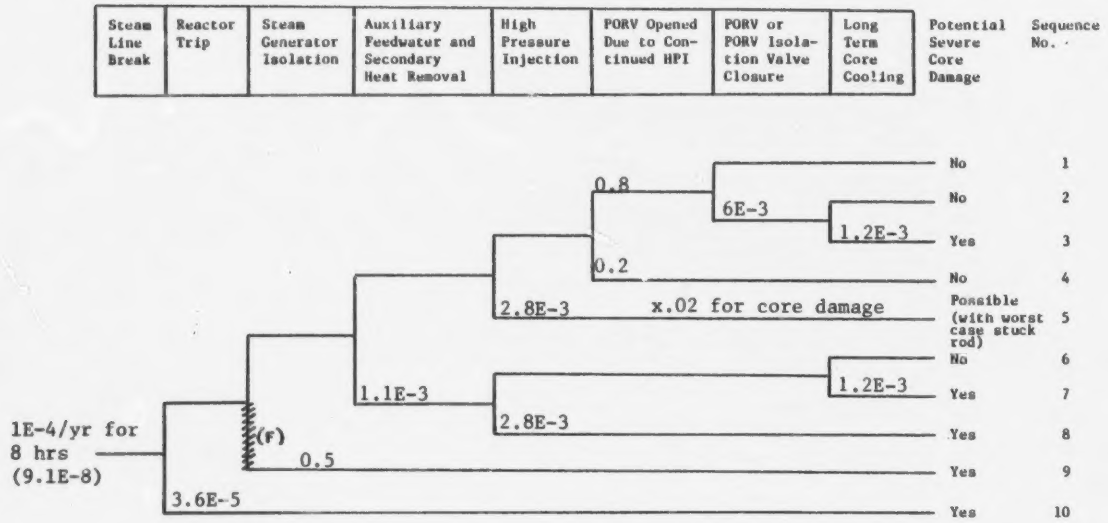
NSIC 120995 — Sequence of Interest for Both Sump Suction Valves to Decay Heat Pumps Fail to Open at Rancho Seco


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 360 hrs
(1.7E-3)
(F) 1.0
3.9E-3
(F) 1.1E-3
1.3E-5
0.1
(F) 1.0
No
Yes
No
Yes
Yes
No
Yes
Yes
No
Yes
No
Yes
Yes
Yes
Yes
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15

P = 7.8E-6 (SC = 51)

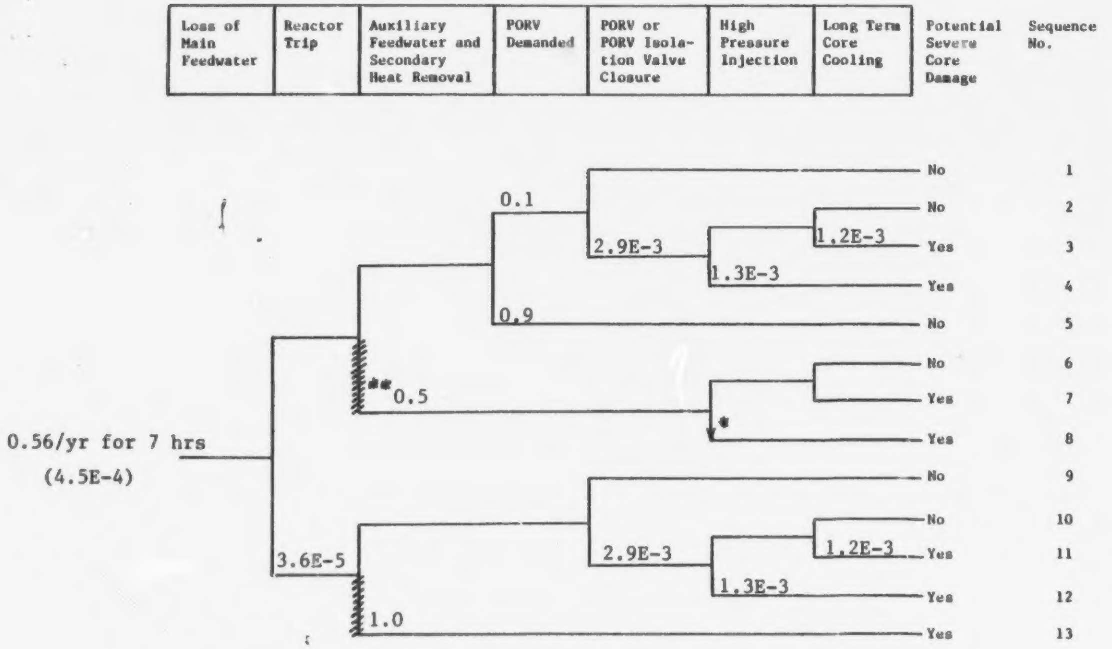
NSIC 121533 — Sequence of Interest for Two Diesels Trip at Brunswick 1

159


Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1E-4/yr for 8 hrs (9.1E-8)
3.6E-5
(F)
0.5
1.1E-3
2.8E-3
2.8E-3
0.8
0.2
6E-3
1.2E-3
1.2E-3
x.02 for core damage
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

P = 4.55E-8 (SC = 73)

NSIC 122366 — Sequence of Interest for Steam Line Break Instrumentation and Control System Failure at Arkansas Nuclear 1

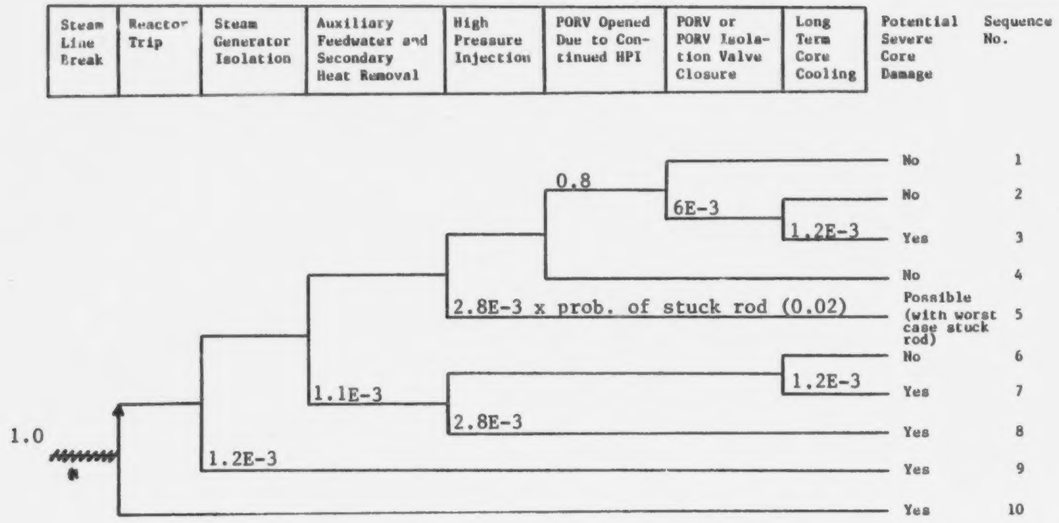

Loss of Main Feedwater
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.56/yr for 7 hrs
(4.5E-4)
3.6E-5
1.0
**0.5
0.1
0.9
2.9E-3
1.3E-3
1.2E-3
*
2.9E-3
1.3E-3
1.2E-3
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

P = 2.25E-4 (SC = 36)

NSIC 123118 — Sequence of Interest for Both AFW Pumps Unavailable at Rancho Seco

*Use of HPI following failure of AFW not included in operating procedures

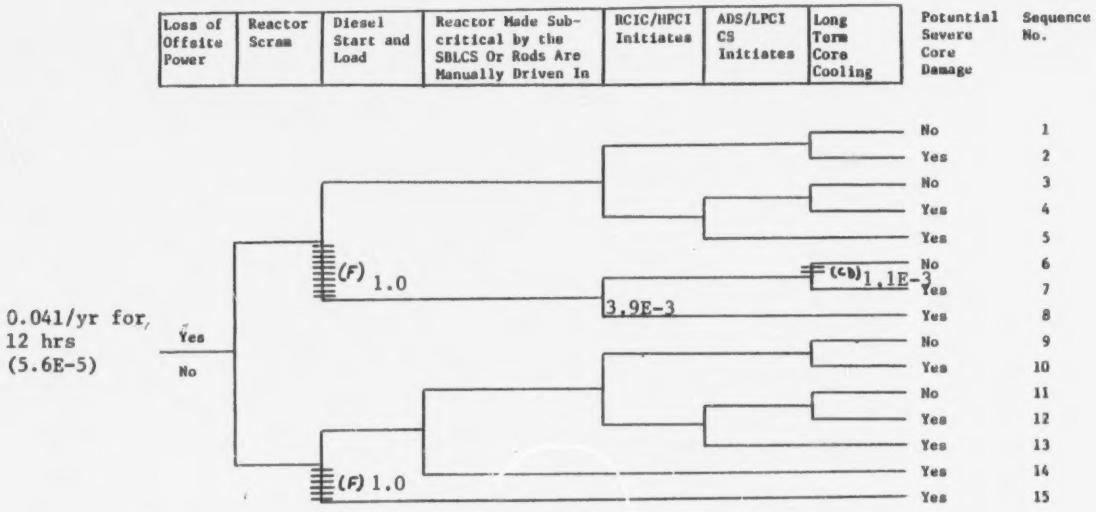
**Operator action required for degraded


Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
*
0.8
6E-3
1.2E-3
2.8E-3 x prob. of stuck rod (0.02)
1.1E-3
1.2E-3
2.8E-3
1.2E-3
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

P = 1.26E-3 (SC = 29)

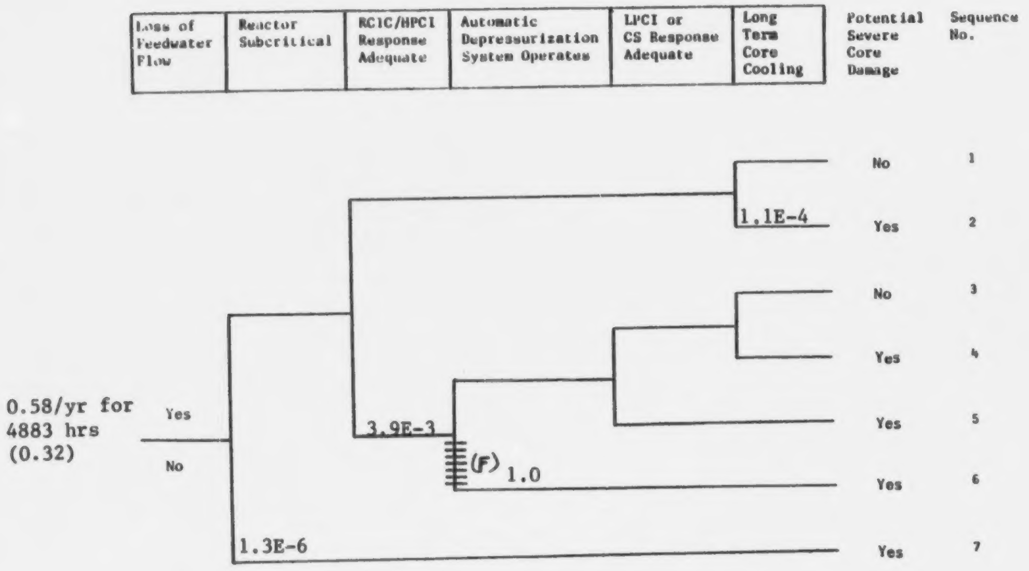
NSIC 123150 — Sequence of Interest for Excess Cooldown Rate Results from Loss of ICS Power at Crystal River 3

*small


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for, 12 hrs (5.6E-5)
Yes
No
(F) 1.0
3.9E-3
(CD) 1.1E-3
(F) 1.0
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

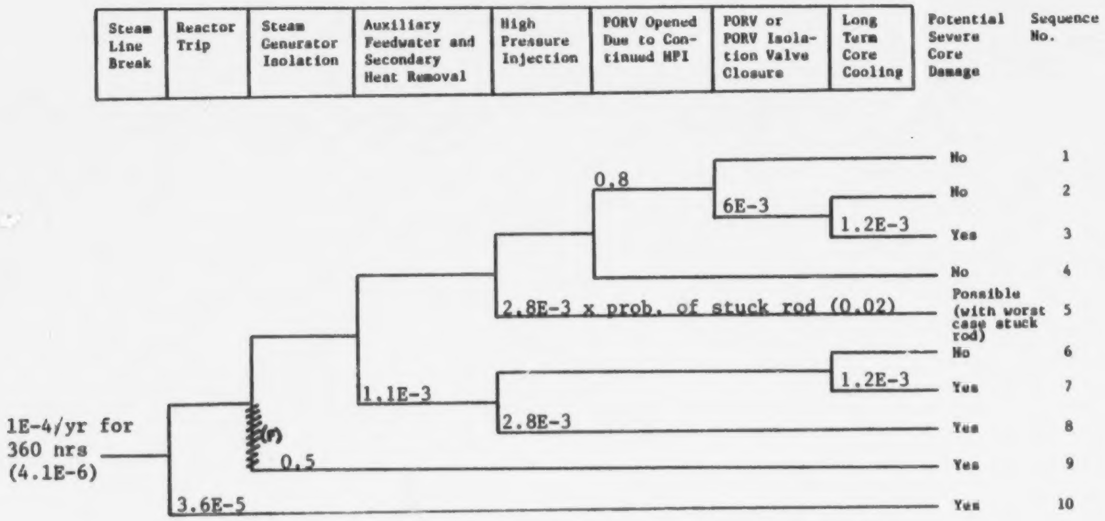
P = 2.6E-7 (SC = 66)

NSIC 124201 — Sequence of Interest for a Diesel Generator's Field Fails to Flash at Dresden 3


Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.58/yr for 4883 hrs (0.32)
Yes
No
1.1E-4
3.9E-3
(F)
1.0
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

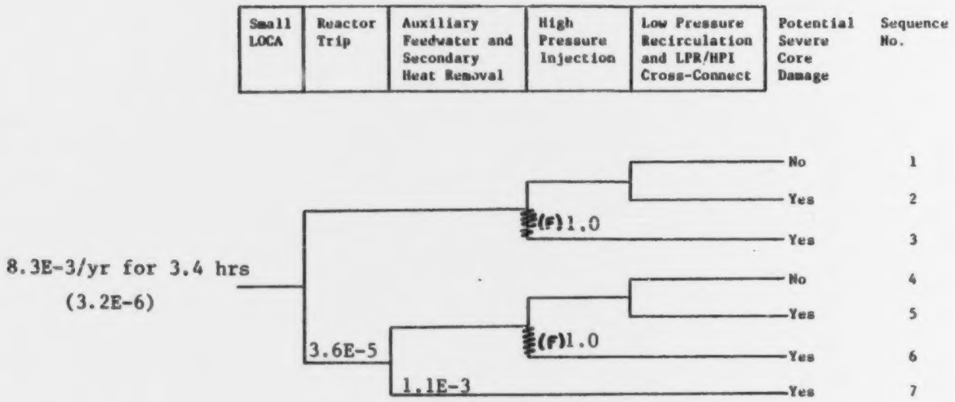
P = 1.3E-3 + addl. cont. (LOOP, LOCA, MSLB), 8E-4 = 2.1E-3 x prob. of occurring at power (0.75) = 1.6E-3 (SC = 28)

NSIC 124222 — Sequence of Interest for Six Main Steam Relief Valves Fail to Lift Properly at Duane Arnold


Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1E-4/yr for 360 hrs (4.1E-6)
0.8
6E-3
1.2E-3
2.8E-3 x prob. of stuck rod (0.02)
1.1E-3
1.2E-3
2.8E-3
(F)
0.5
3.6E-5
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

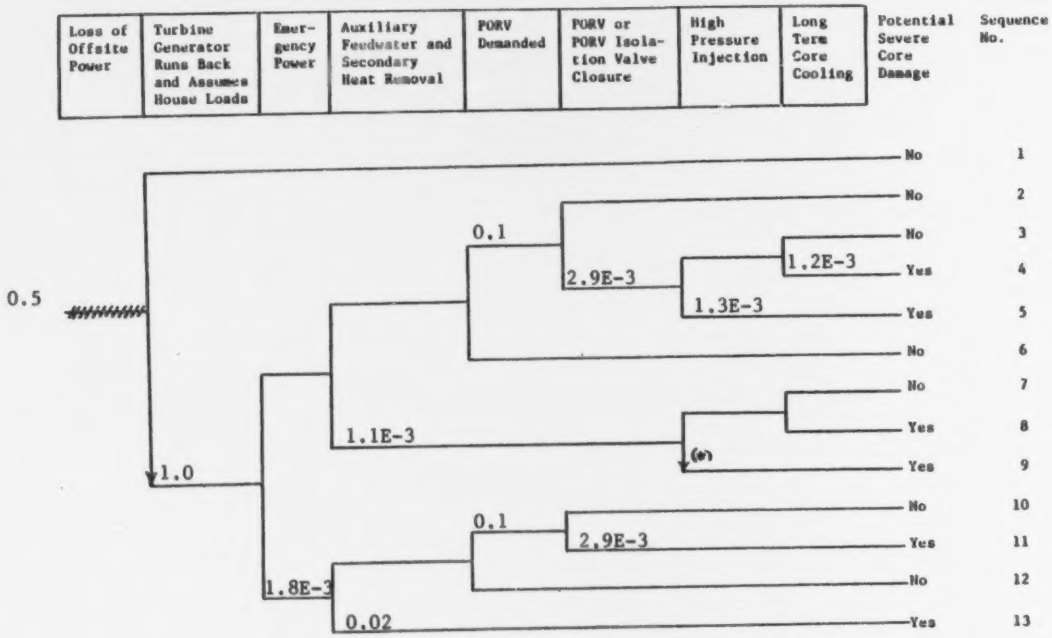
P = 2.1E-6 x prob. of reactor at power or immediately after shutdown (0.75) = 1.6E-6 (SC = 58)

NSIC 124920 — Sequence of Interest for Excessive Cooldown Rate Experienced During Testing at Crystal River 3


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
8.3E-3/yr for 3.4 hrs
(3.2E-6)
(F)1.0
3.6E-5
(F)1.0
1.1E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 3.2E-6 + addl. cont. (LOFW), 6.3E-8 = 3.3E-6 (SC = 55)

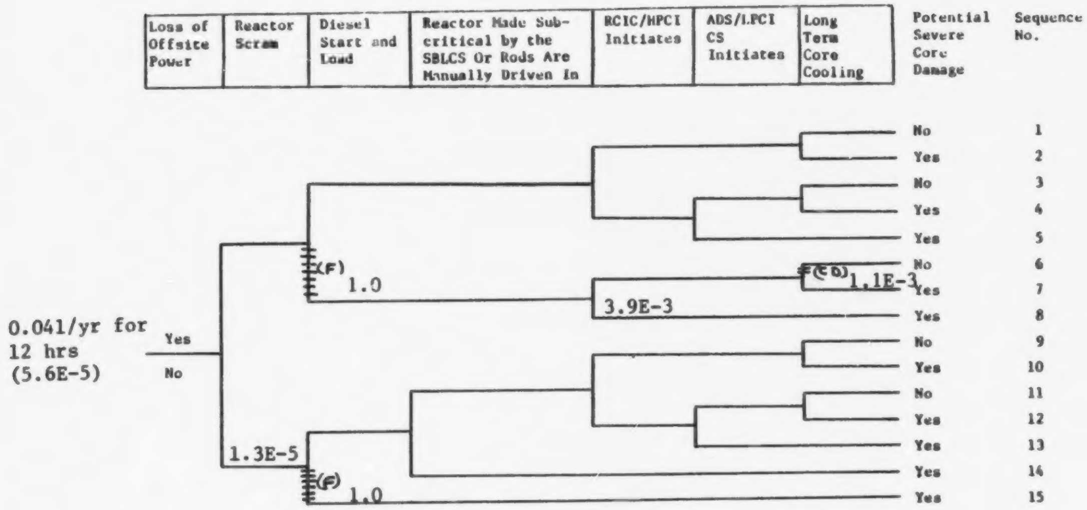
NSIC 125106 – Sequence of Interest for Both SI Pumps and One Charging Pump Out of Service During Heatup at Salem 1


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
(*)
0.1
2.9E-3
1.8E-3
0.02
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 5.7E-4 x prob. of event occurring at power (0.75) = 4.3E-4 (SC = 34)

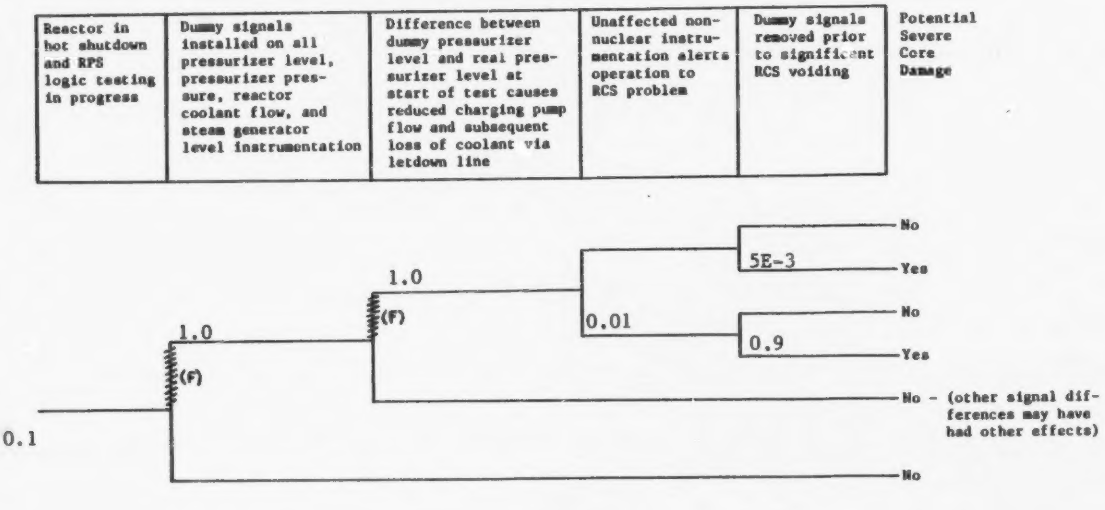
NSIC 125563 – Sequence of Interest for Off-Site Power Lost at St. Lucie 1

*not included in mitigation procedures.


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15
(F) 1.0
3.9E-3
(CD) 1.1E-3
0.041/yr for 12 hrs (5.6E-5)
Yes
No
1.3E-5
(F) 1.0

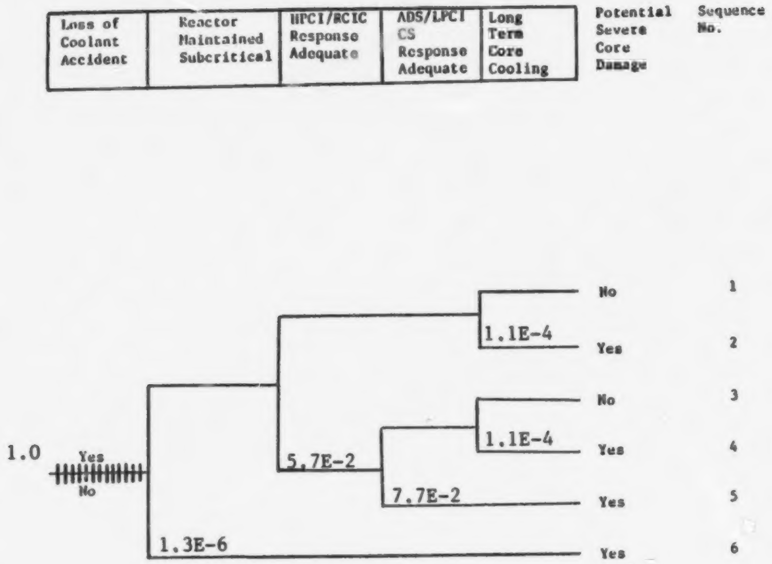
P = 2.6E-7 (SC = 66)

NSIC 127010 – Sequence of Interest for Failure of Two Diesel Generators at Dresden 2


Reactor in hot shutdown and RPS logic testing in progress
Dummy signals installed on all pressurizer level, pressurizer pressure, reactor coolant flow, and steam generator level instrumentation
Difference between dummy pressurizer level and real pressurizer level at start of test causes reduced charging pump flow and subsequent loss of coolant via letdown line
Unaffected non-nuclear instrumentation alerts operation to RCS problem
Dummy signals removed prior to significant RCS voiding
Potential Severe Core Damage
No
5E-3
Yes
1.0
(F)
0.01
No
0.9
Yes
1.0
(F)
No - (other signal differences may have had other effects)
0.1
No

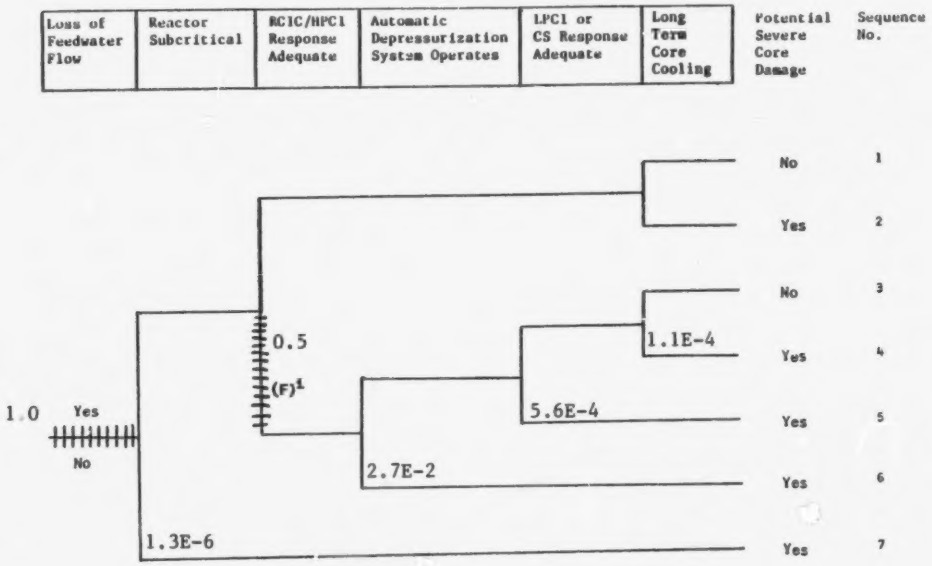
P = 1.4E-3 (SC = 29)

NSIC 127384 – Sequence of Interest for Dummy Loads Installed on All Safety Systems at Zion 2


Loss of Coolant Accident
Reactor Maintained Subcritical
HPCI/RCIC Response Adequate
ADS/LPCI CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
Yes
No
1.1E-4
5.7E-2
1.1E-4
7.7E-2
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6

P = 1.8E-3 (SC = 27)

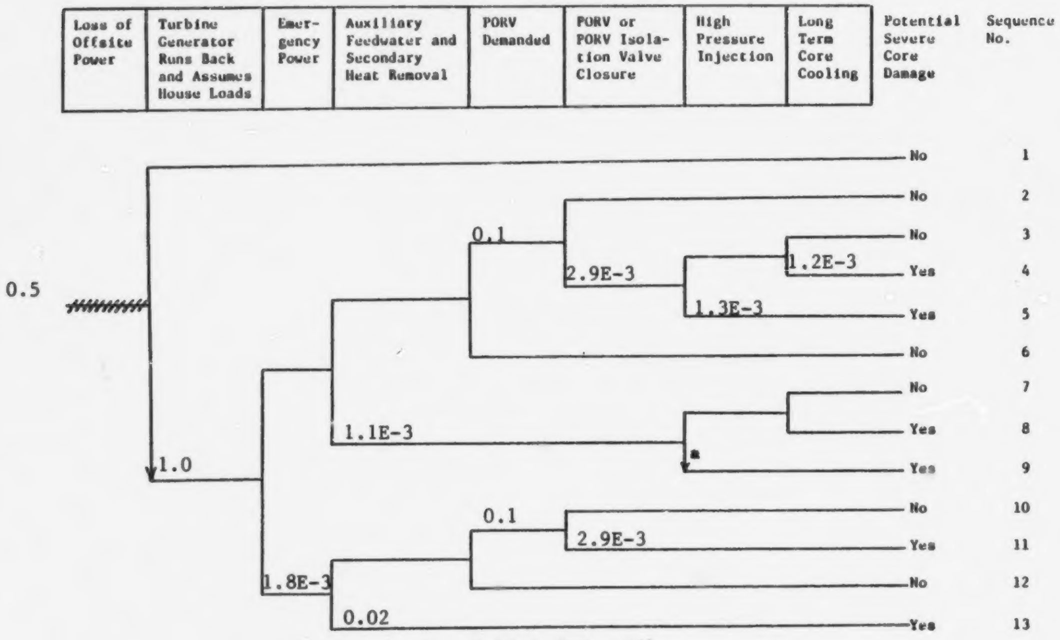
NSIC 128569 — Sequence of Interest for Safety Relief Valve Fails to Reset at Brunswick 2


Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
Yes
No
0.5
(F)1
1.1E-4
5.6E-4
2.7E-2
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 1.4E-2 (SC = 19)

NSIC 128906 — Sequence of Interest for No Break Power Panel De-energized at Cooper

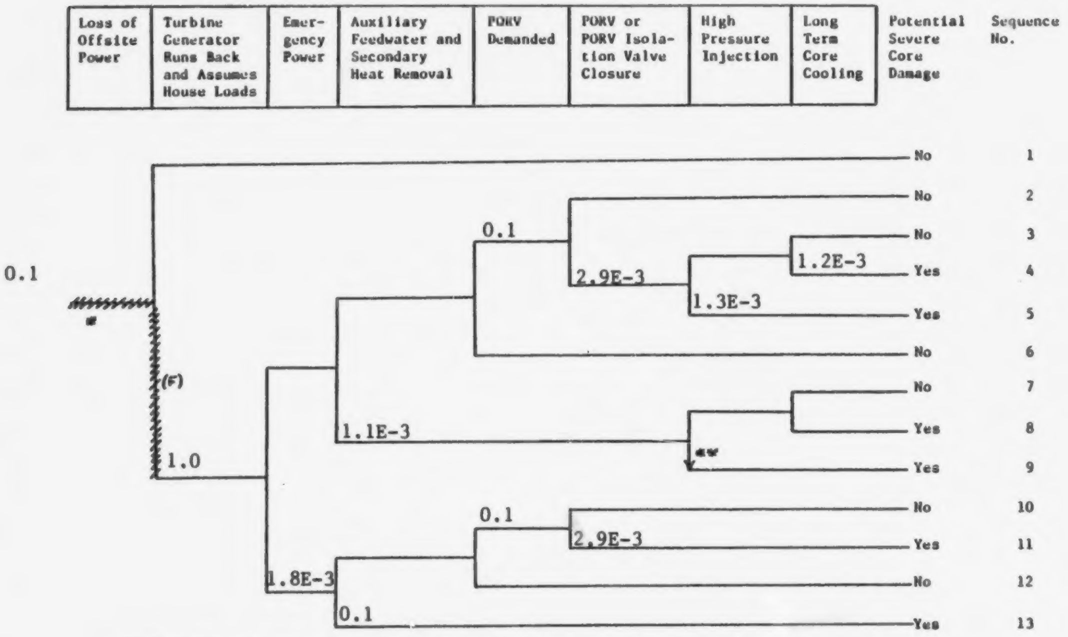
[1] Success requires restoration of power to the NBPP.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
*
1.8E-3
0.1
2.9E-3
0.02
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 5.7E-4 (SC = 32)

NSIC 128935 — Sequence of Interest for Plant 161 kV Feed Lost Momentarily at Ft. Calhoun 1

*Not included in mitigation procedures.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.1
*
(F)
1.0
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
**
1.8E-3
0.1
2.9E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

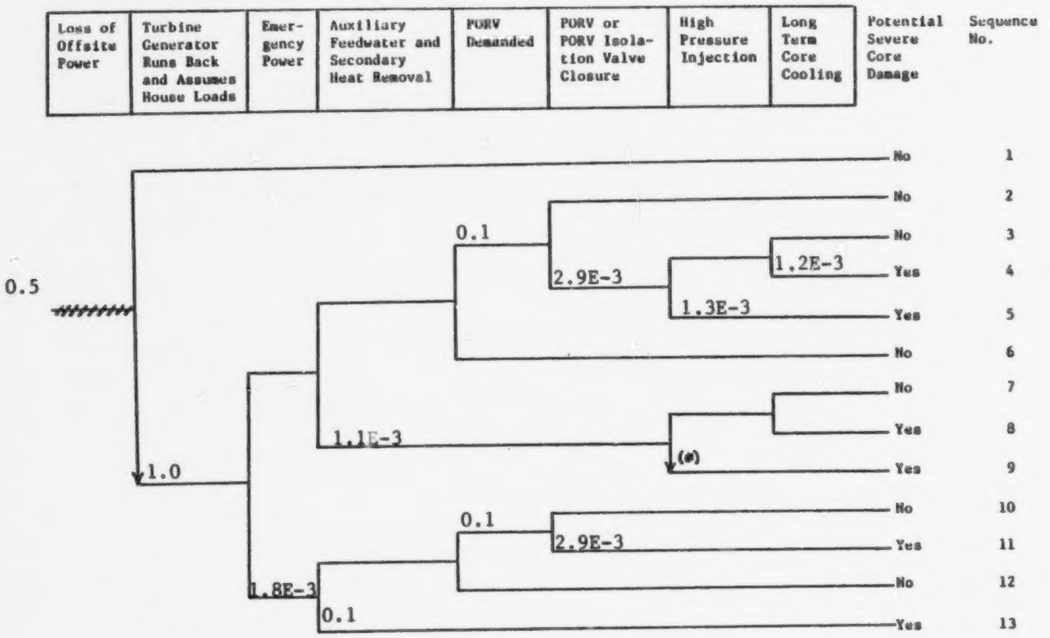
NSIC 130111 — Sequence of Interest for "Blackout" Condition Occurs After Reactor Trip at Cook 1

*success requires manual transfer to an emergency reserve power source.

P = 1.3E-4 (SC = 39)

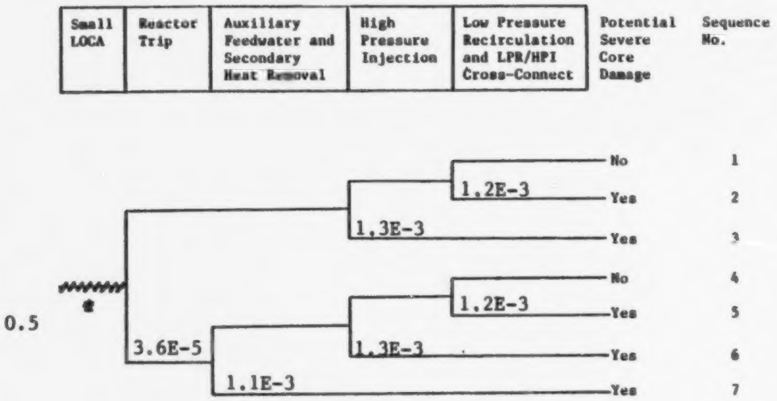
**not included in mitigation procedures.

BEST DOCUMENT AVAILABLE


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
(*)
0.1
2.9E-3
1.8E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 6.4E-4 (SC = 32)

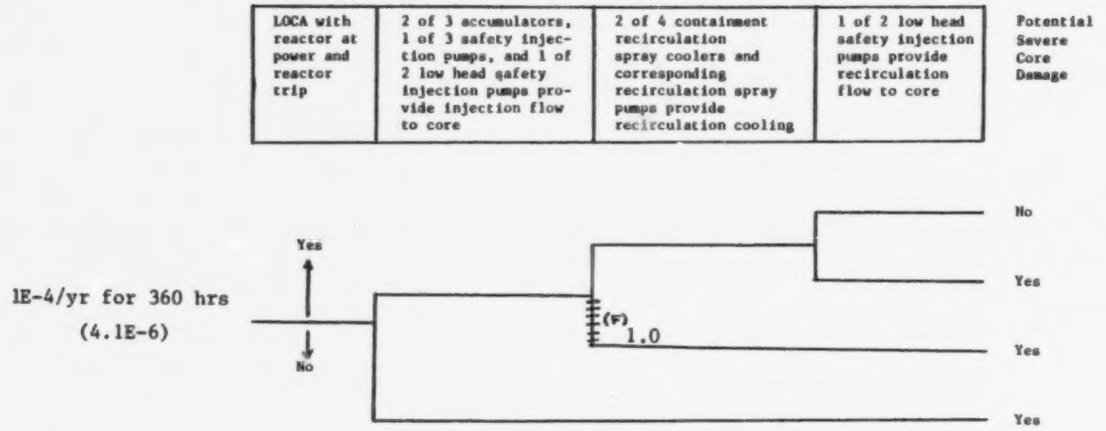
NSIC 130119 — Sequence of Interest for a Complete Loss of Offsite Power at Palisades
*Not included in mitigation procedures.


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
0.5
*
1.2E-3
1.3E-3
1.2E-3
3.6E-5
1.3E-3
1.1E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 1.25E-3 (SC = 29)

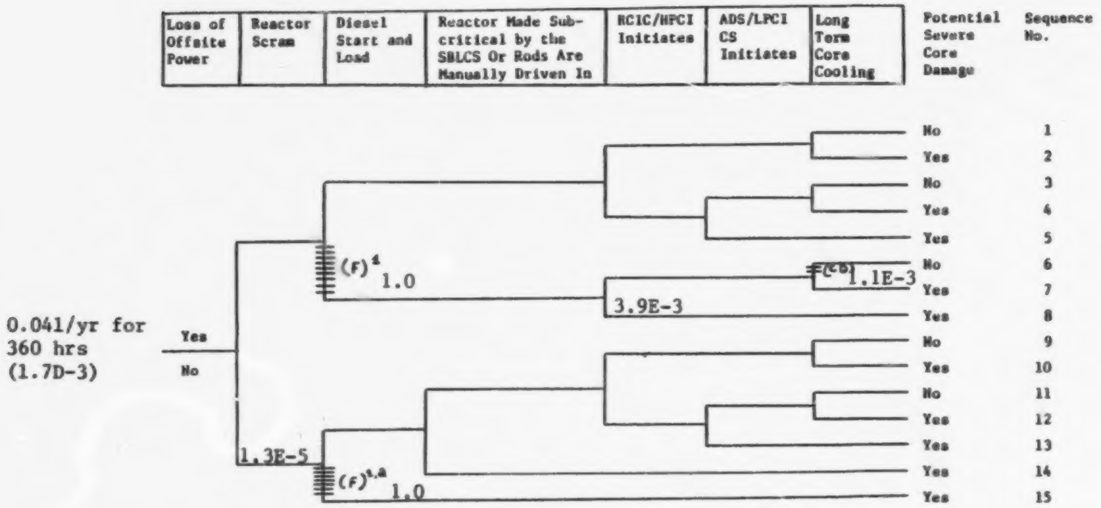
NSIC 130788 — Sequence of Interest for Spurious Half-Trip of SFRCS Causes RCS Pressure Rise at Davis-Besse 1

*failure requires operator error in failing to close PORV block valve.


LOCA with reactor at power and reactor trip
2 of 3 accumulators, 1 of 3 safety injection pumps, and 1 of 2 low head safety injection pumps provide injection flow to core
2 of 4 containment recirculation spray coolers and corresponding recirculation spray pumps provide recirculation cooling
1 of 2 low head safety injection pumps provide recirculation flow to core
Potential Severe Core Damage
1E-4/yr for 360 hrs
(4.1E-6)
Yes
No
(F)
1.0
No
Yes
Yes
Yes

P = 4.1E-6 x prob. of occurring at power (0.75) = 3.1E-6 (SC = 55)

NSIC 130889 — Sequence of Interest for Emergency Service Water Valves Found Flooded at Surry 2

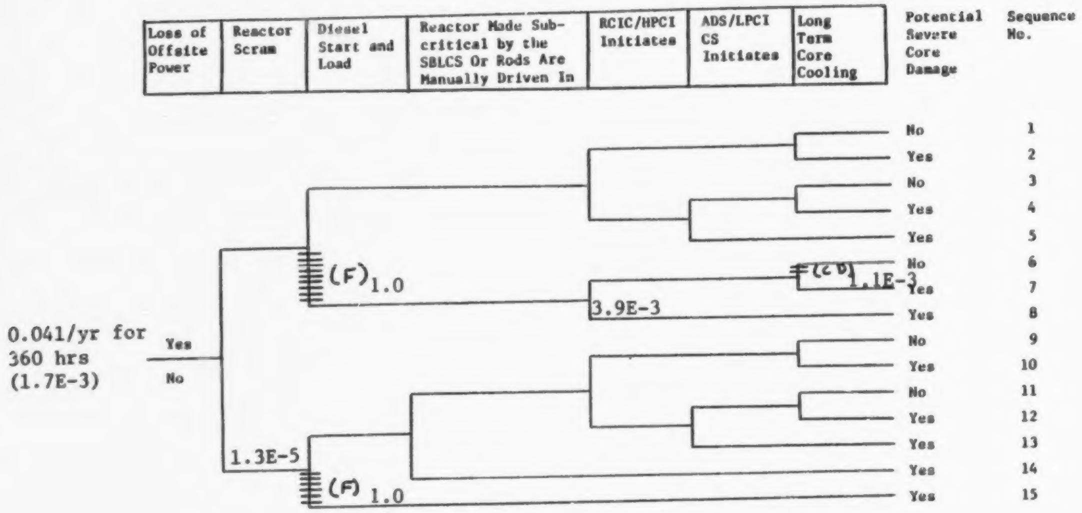

Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 360 hrs (1.7D-3)
Yes
No
(F)¹
1.0
3.9E-3
(CD)
1.1E-3
1.3E-5
(F)¹˒²
1.0
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 7.8E-6 (SC = 51)

NSIC 131225 — Sequence of Interest for Two Diesel Generators Fail to Start at Peach Bottom 2

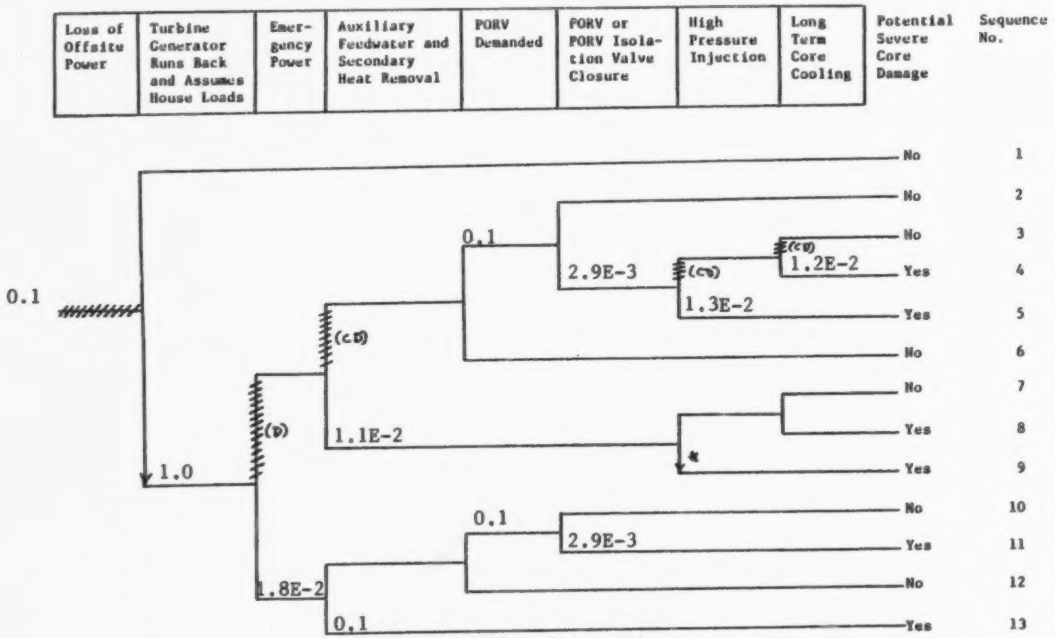
[1] Resetting the jacket temperature alarm would result in a success.

[2] Proper loading of the operating diesels would allow success of alternate shutdown procedures or systems.


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 360 hrs (1.7E-3)
Yes
No
(F) 1.0
(CD) 1.1E-3
3.9E-3
1.3E-5
(F) 1.0
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 7.8E-6 (SC = 51)

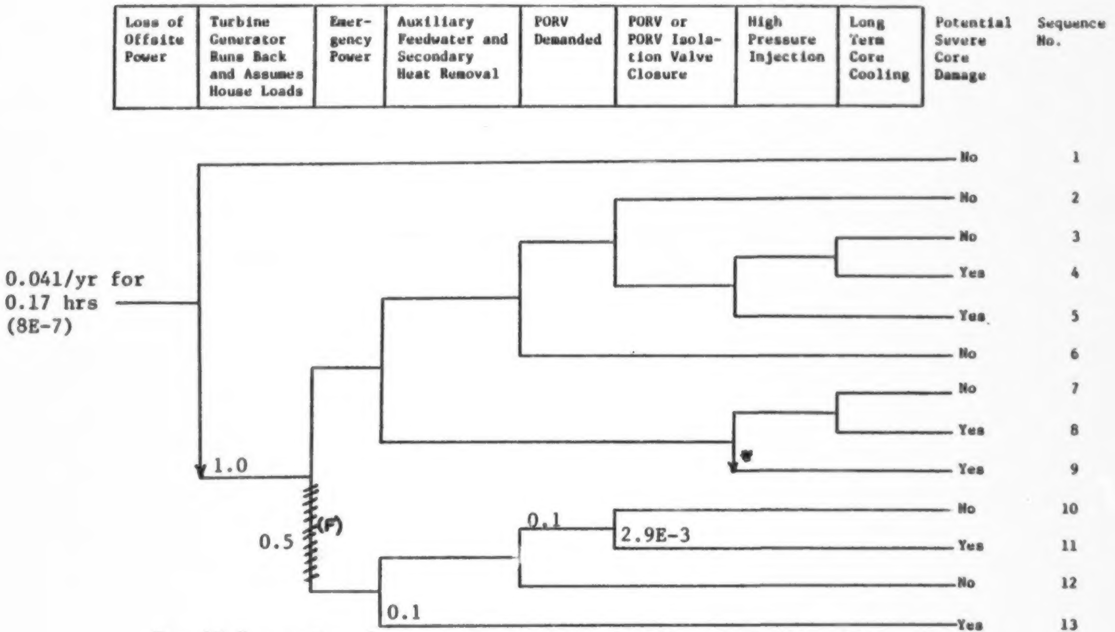
NSIC 132155 — Sequence of Interest of a Diesel Generator Trips During Testing at Dresden 3


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.1
1.0
(D)
(CD)
0.1
2.9E-3
(CD)
(CD) 1.2E-2
1.3E-2
1.1E-2
*
1.8E-2
0.1
2.9E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1.28E-3 (SC = 29)

NSIC 132927 — Sequence of Interest for Both 13.8 kv Buses De-Energized at Davis-Besse 1

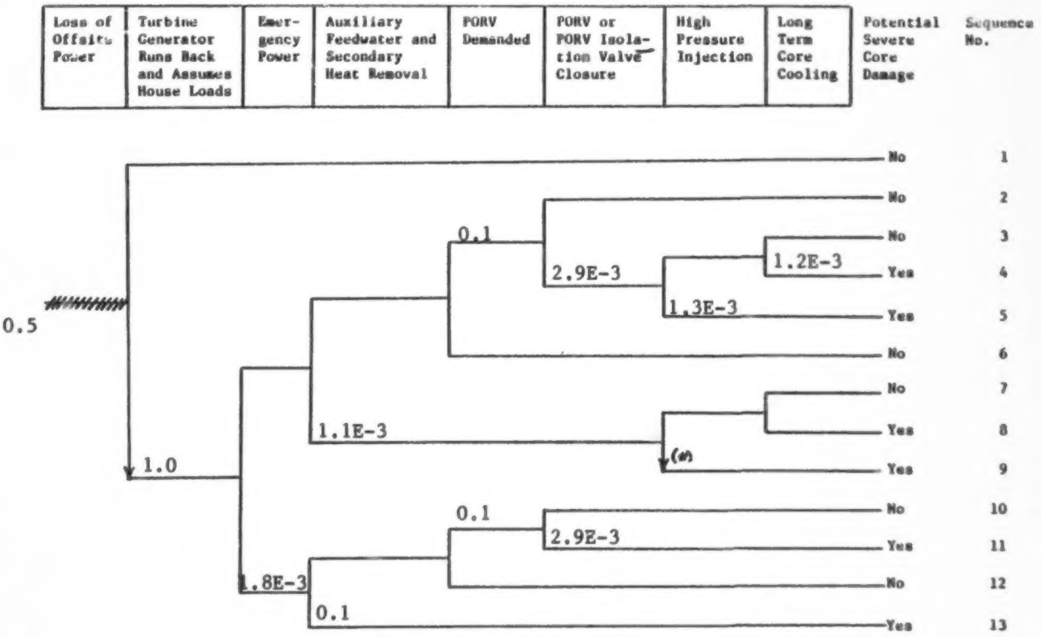
*Not included in operating procedures.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for
0.17 hrs
(8E-7)
1.0
0.5
(F)
0.1
2.9E-3
0.1
*
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 4E-8 x prob. of occurring at power (0.75) = 3E-8 (SC = 75)

NSIC 132942 — Sequence of Interest for Both Diesel Generators Unavailable at Prairie Island 1

*Not included in operating procedures

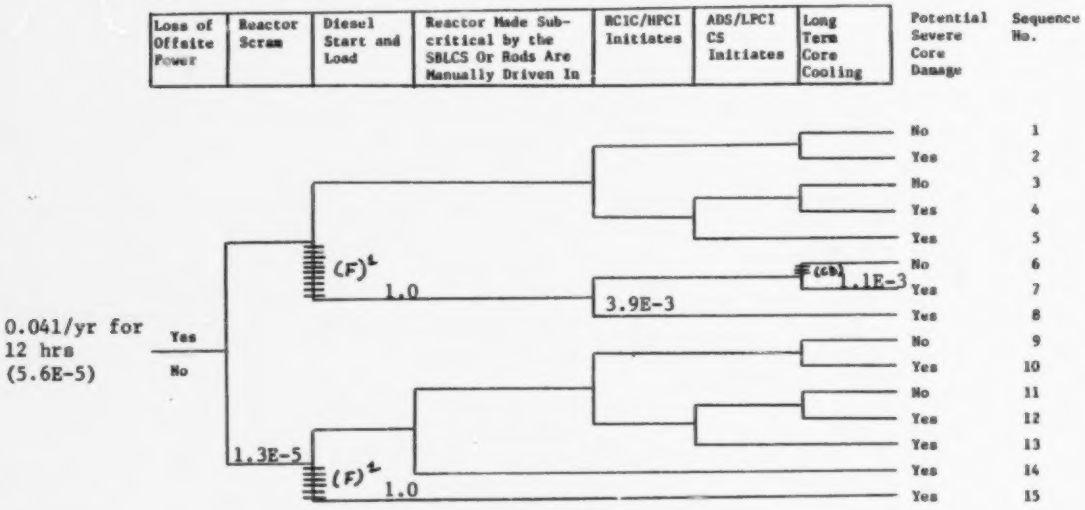

Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
(*)
0.1
2.9E-3
1.8E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 6.4E-4 (SC = 32)

NSIC 132943 — Sequence of Interest for Complete Loss of Offsite Power at Palisades

*Not included in mitigation procedures.

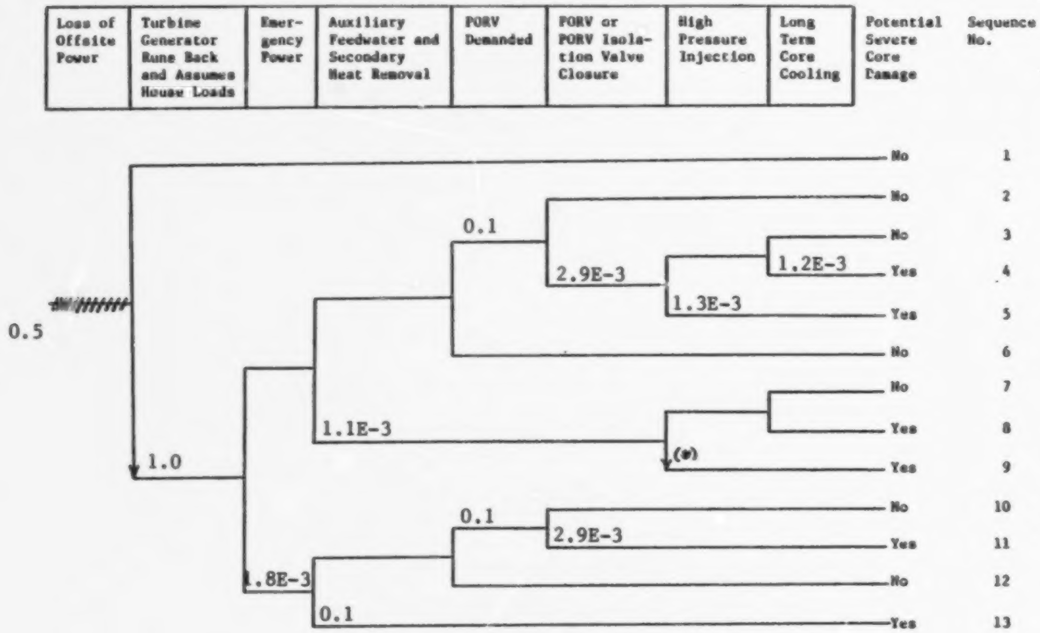
BEST DOCUMENT AVAILABLE


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 12 hrs (5.6E-5)
Yes
No
(F)¹
1.0
3.9E-3
(CD)
1.1E-3
1.3E-5
(F)¹
1.0
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 2.6E-7 (SC = 66)

NSIC 132947 – Sequence of Interest of a Diesel Generator Fails to Start at Dresden 2

[1]Success results if, step 3 of "The Failure Sequence Was:" is successful during the LOOP


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
(*)
0.1
2.9E-3
1.8E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 6.4E-4 (SC = 32)

NSIC 132958 – Sequence of Interest for Complete Loss of Offsite Power at Palisades

*Not included in mitigation procedures.

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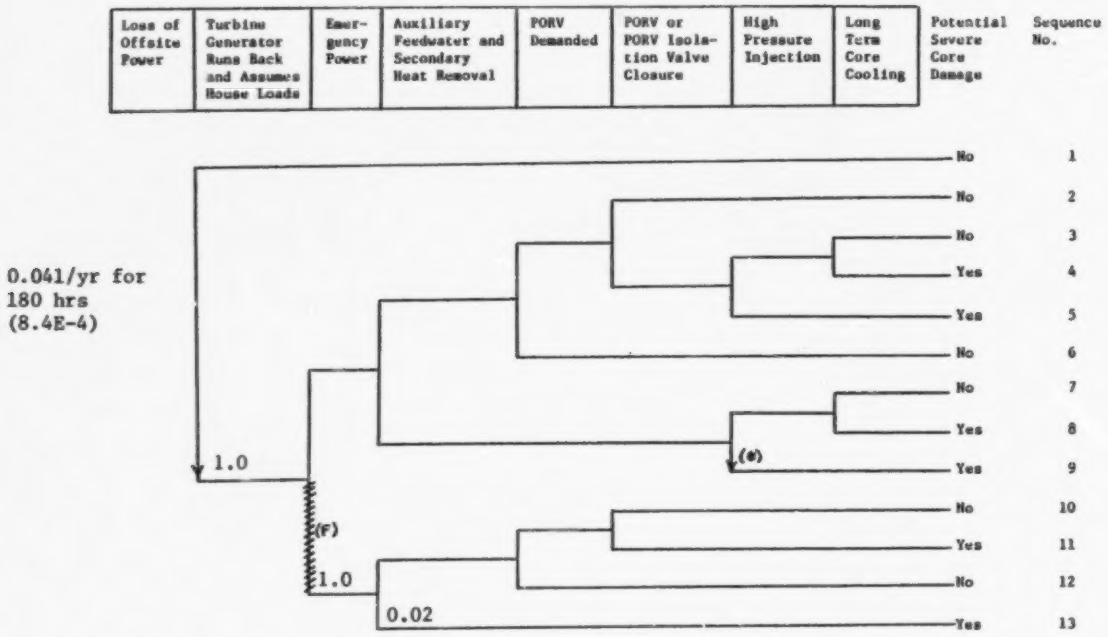
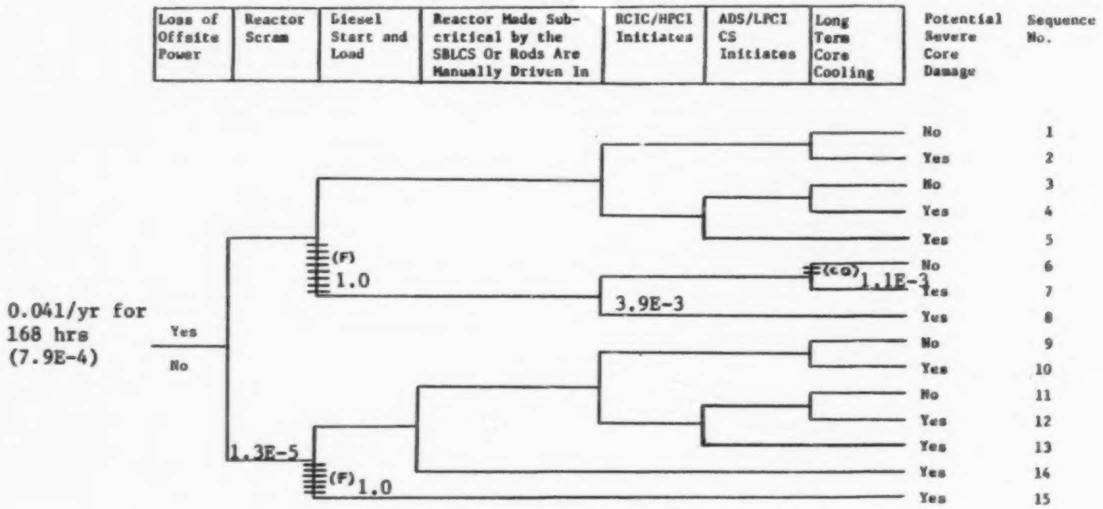

Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 180 hrs (8.4E-4)
1.0
(F)
1.0
0.02
(*)
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1.68E-5 x prob. of occurring at power (0.75) = 1.3E-5 (SC = 49)

NSIC 132979 — Sequence of Interest for Both Diesel-Generator Fuel Supply Valves Found Shut at Millstone 2
*Not included in mitigation procedures.


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 168 hrs (7.9E-4)
Yes
No
(F)
1.0
3.9E-3
(CO)
1.1E-3
1.3E-5
(F)
1.0
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 3.9E-6 (SC = 54)

NSIC 133004 - Sequence of Interest for Three Out of Four Diesels Inoperable at Peach Bottom Atomic Power Station

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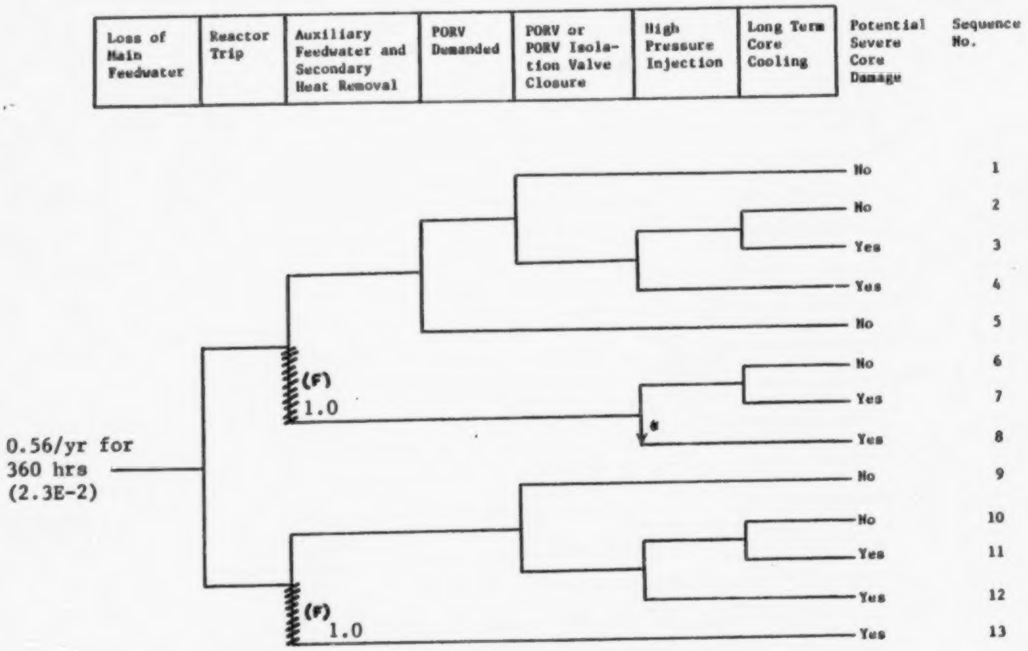
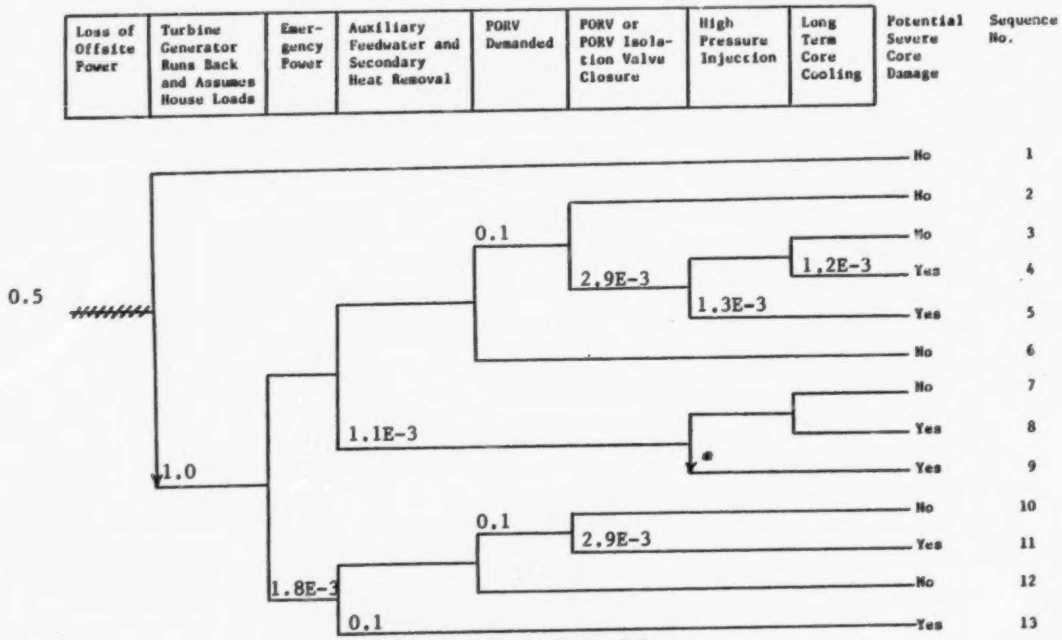

Loss of Main Feedwater
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.56/yr for 360 hrs (2.3E-2)
(F)
1.0
(F)
1.0
*
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

P = 2.3E-2 + addl. cont. (LOOP), 1.64E-3 = 2.5E-2 (SC = 16)

NSIC 133706 – Sequence of Interest for Control of Both Auxiliary Feed Pump Turbines Lost at Davis-Besse 1

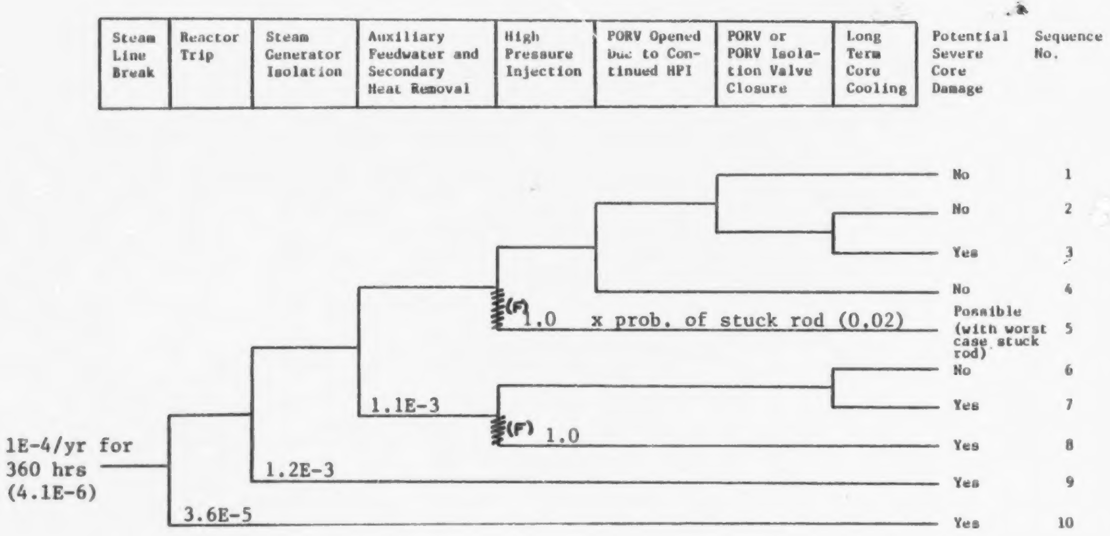
*not included in mitigation procedures


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
0.1
2.9E-3
1.3E-3
1.2E-3
1.1E-3
*
0.1
2.9E-3
1.8E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 6.4E-4 (SC = 32)

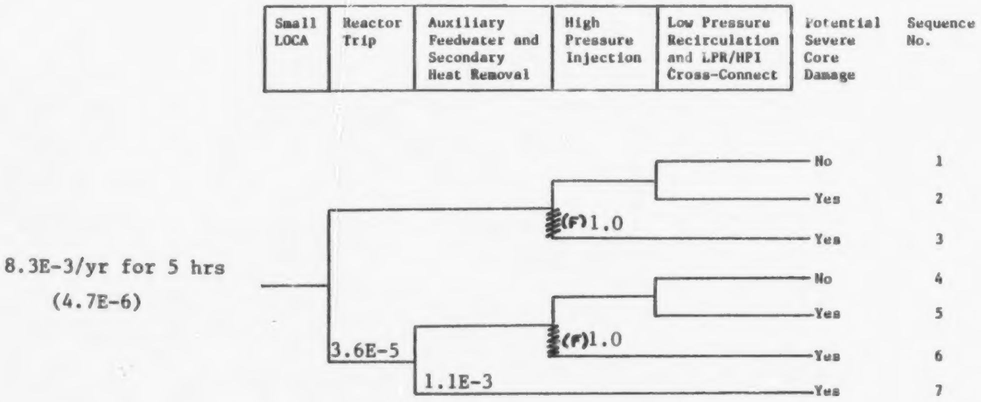
NSIC 135006 – Sequence of Interest for Loss of Offsite Powe. Occurs at Farley 1

*Not included in mitigation procedures.


Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10
(F) 1.0 x prob. of stuck rod (0.02)
1.1E-3
(F) 1.0
1E-4/yr for 360 hrs (4.1E-6)
1.2E-3
3.6E-5

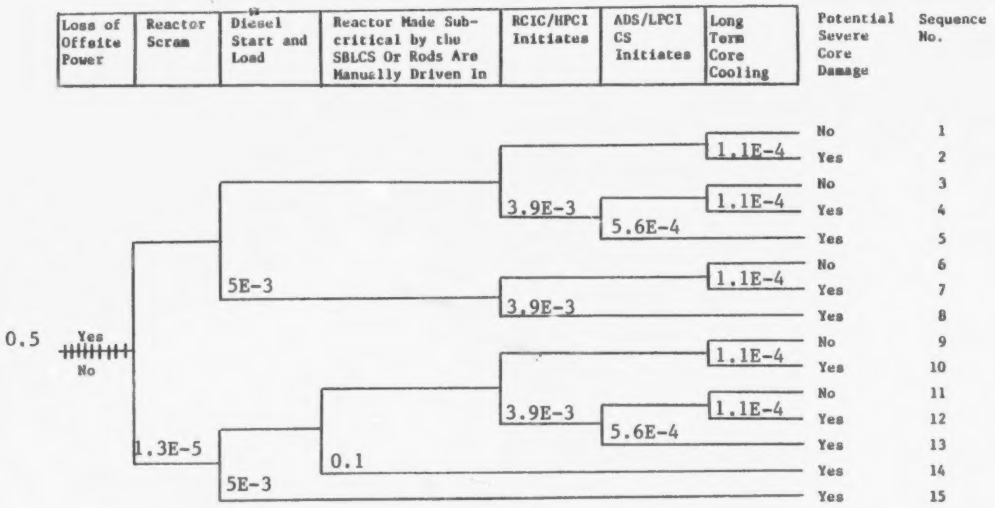
P = 8.7E-8 x prob. of occurring at power (0.75) = 6.5E-8 (SC = 72)

NSIC 135077 – Sequence of Interest for Boron Injection Tank Thermo Well Coupling Rupture at Robinson 2


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7
(F) 1.0
(F) 1.0
8.3E-3/yr for 5 hrs (4.7E-6)
3.6E-5
1.1E-3

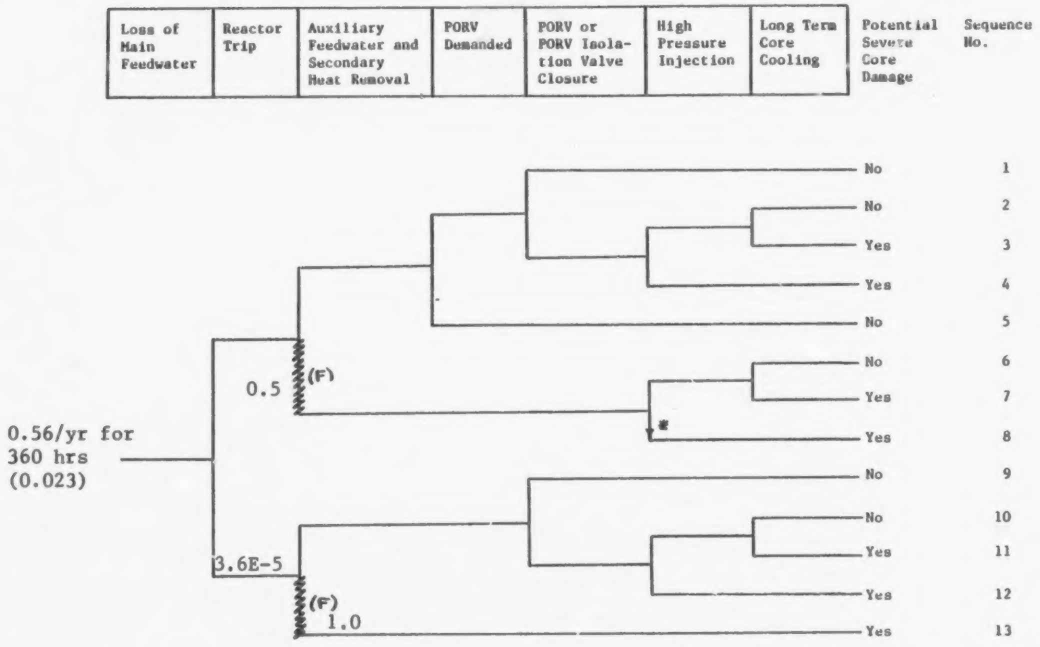
P = 4.7E-6 + addl. cont. (LOFW), 9.3E-8 = 4.8E-6
x prob. of occurring at power (0.75) = 3.6E-6 (SC = 54)

NSIC 135079 – Sequence of Interest for Inoperable Safety Injection Pumps at Robinson 2


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Sub-critical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
Yes
No
1.3E-5
5E-3
5E-3
0.1
3.9E-3
3.9E-3
3.9E-3
5.6E-4
5.6E-4
1.1E-4
1.1E-4
1.1E-4
1.1E-4
1.1E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 6.7E-5 (SC = 42)

NSIC 135932 – Sequence of Interest of the Loss of All Transmission Lines at Pilgrim 1


Loss of Main Feedwater
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.56/yr for 360 hrs (0.023)
0.5
(F)
3.6E-5
(F)
1.0
*
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

P = 1.1E-2 + addl. cont. (LOOP), 8.4E-4 = 1.2E-2 (SC = 19)

NSIC 137305 – Sequence of Interest for Auxiliary Feedwater System Failures at Farley 1
* not included in mitigation sequence

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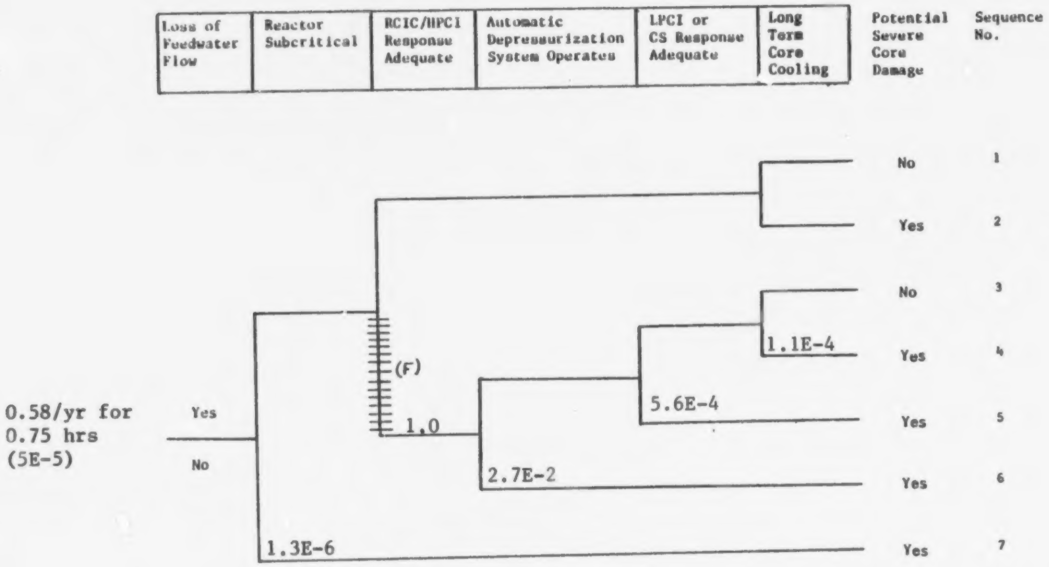
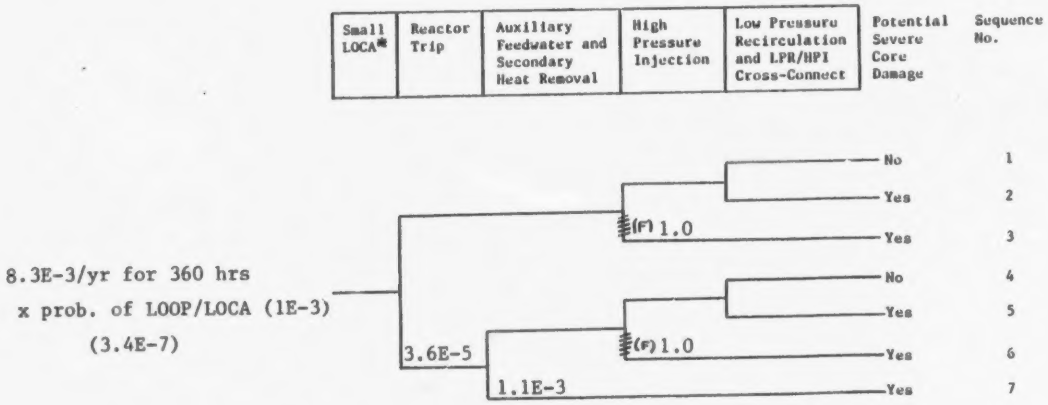
[redacted]



Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.58/yr for 0.75 hrs (5E-5)
Yes
No
(F)
1.0
1.1E-4
5.6E-4
2.7E-2
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 1.3E-6 + addl. cont. (LOOP, LOCA, MSLB), 3E-7 = 1.6E-6 (SC = 58)

NSIC 137335 — Sequence of Interest for Operator Error Renders IC Inoperable With HPCI Out for Repairs at Dresden 2

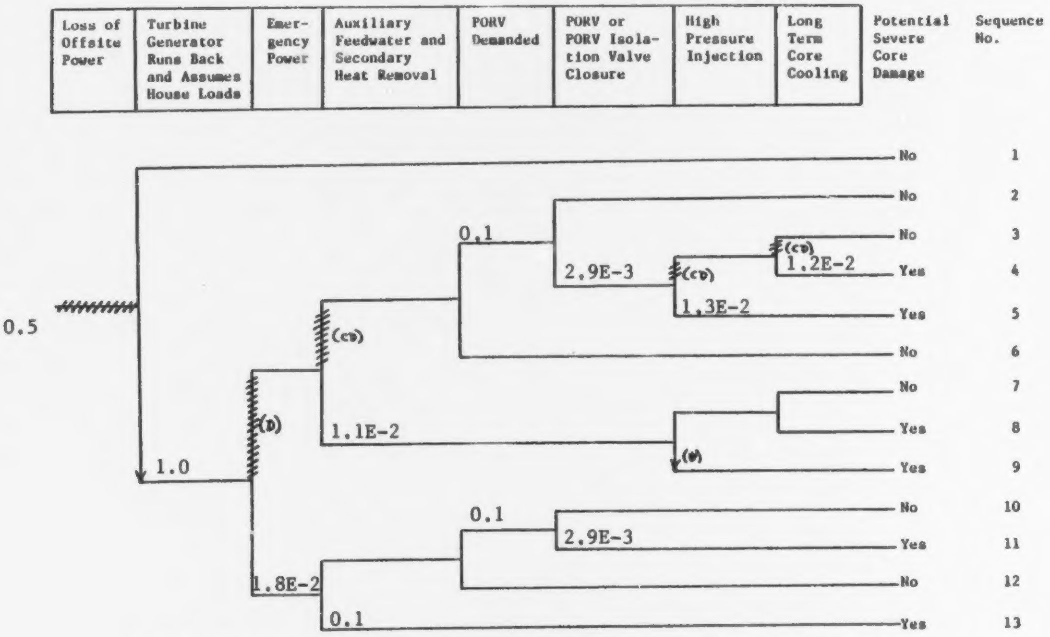


Small LOCA*
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
8.3E-3/yr for 360 hrs x prob. of LOOP/LOCA (1E-3) (3.4E-7)
(F) 1.0
3.6E-5
(F) 1.0
1.1E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 3.4E-7 + addl. cont. (LOOP), 2E-6 = 2.3E-6 (SC = 56)

NSIC 137384 — Sequence of Interest for Failure of Two Makeup Pumps During Testing at Three Mile Island 1

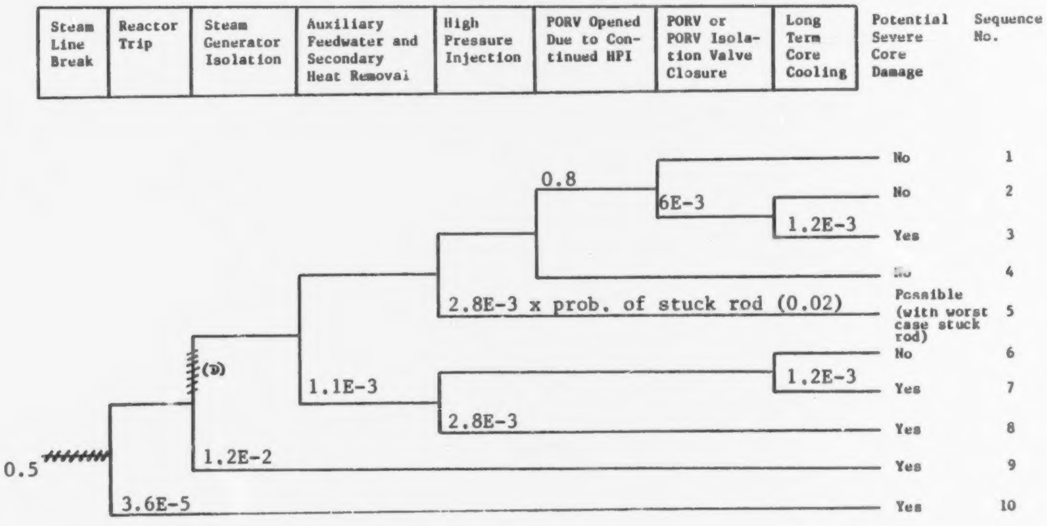
*With loss of offsite power.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
(D)
(CD)
0.1
2.9E-3
(CD)
(CD)
1.2E-2
1.3E-2
1.1E-2
(*)
0.1
2.9E-3
1.8E-2
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 6.4E-3 x prob. of occurring at power (0.75) = 4.8E-3 (SC = 23)

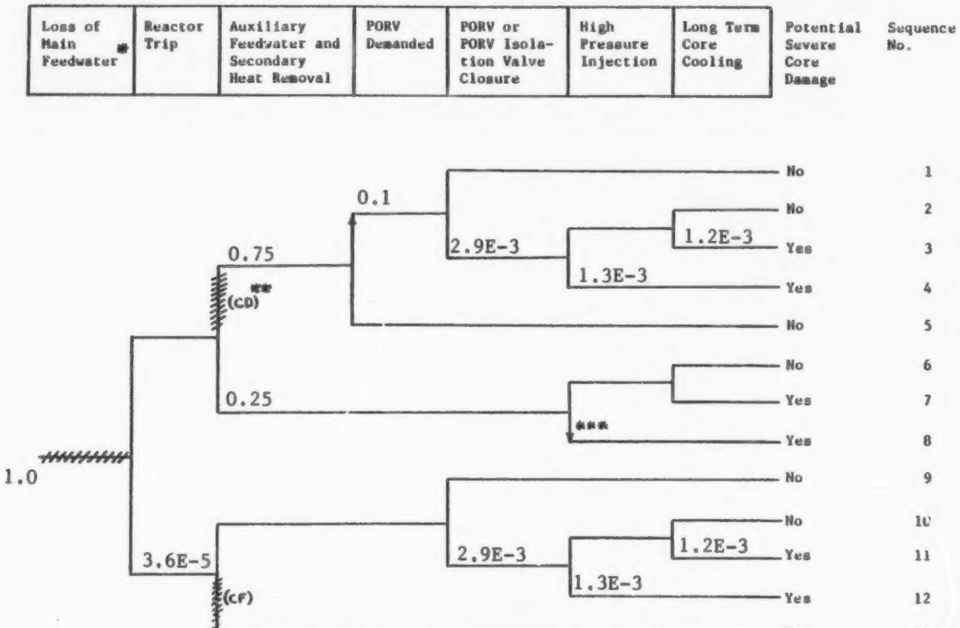
NSIC 137543 — Sequence of Interest for Diesel Generator Fails to Start Following a Loss of All Offsite Power at Calvert Cliffs 1

*Not included in mitigation procedures.


Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
0.8
6E-3
1.2E-3
2.8E-3 x prob. of stuck rod (0.02)
(D)
1.1E-3
1.2E-3
2.8E-3
1.2E-2
3.6E-5
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

P = 6.1E-3 (SC = 22)

NSIC 137918 — Sequence of Interest for Reactor Cooldown Exceeds Limit and Safety Injection at Three Mile Island 2


Loss of Main Feedwater *
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
0.75
(CD) **
0.1
2.9E-3
1.2E-3
1.3E-3
0.25
***
3.6E-5
(CF)
2.9E-3
1.2E-3
1.3E-3
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

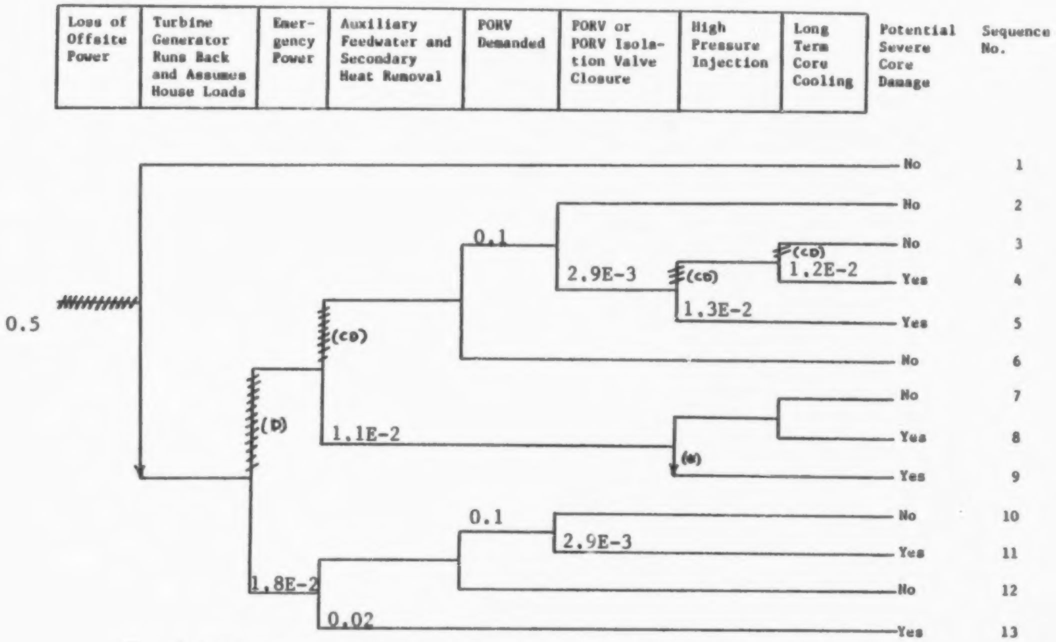
P = 0.25 (SC = 6)

NSIC 138830 – Sequence of Interest for Reactor Cooldown Rate Exceeds Limit Following Reactor Trip at Rancho Seco

*due to NNI-Y power supply trip

**success requires instrument drift in correct direction or operator decision to open AFW control valves when instrumentation indicates steam generators contain water

***not part of mitigation procedure (pre-TMI-2)


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
(D)
(CD)
0.1
2.9E-3
(CD)
(CD)
1.2E-2
1.3E-2
1.1E-2
(*)
1.8E-2
0.1
2.9E-3
0.02
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 5.7E-3 x prob. of occurring at power (0.75) = 4.3E-3 (SC = 23)

NSIC 139565 – Sequence of Interest for Offsite Power Lost at St. Lucie 1

*Not included in mitigation procedures.

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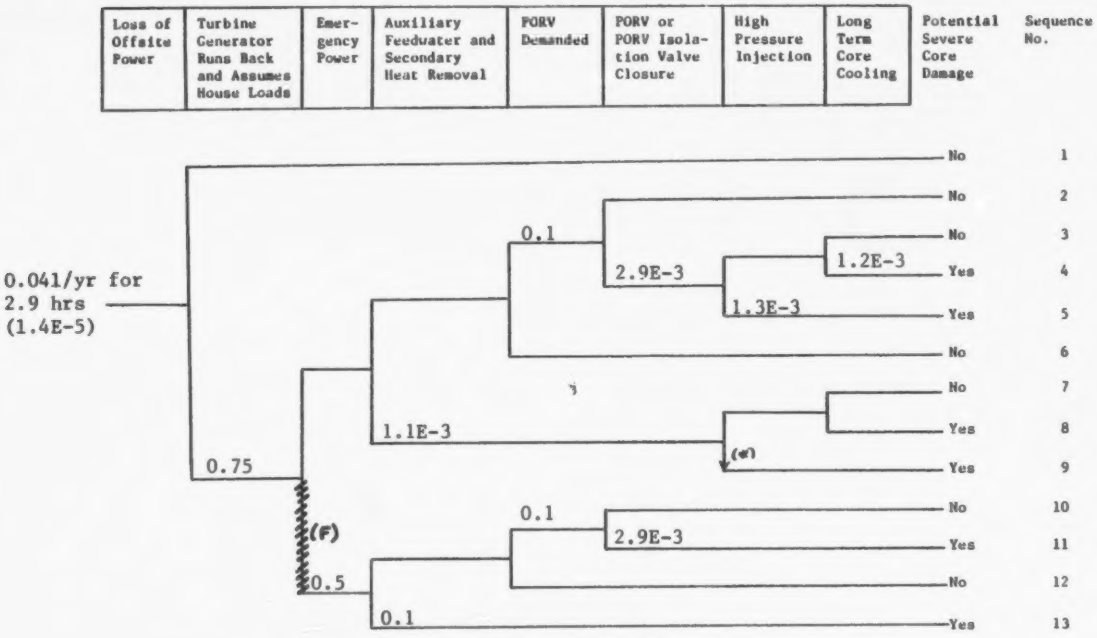
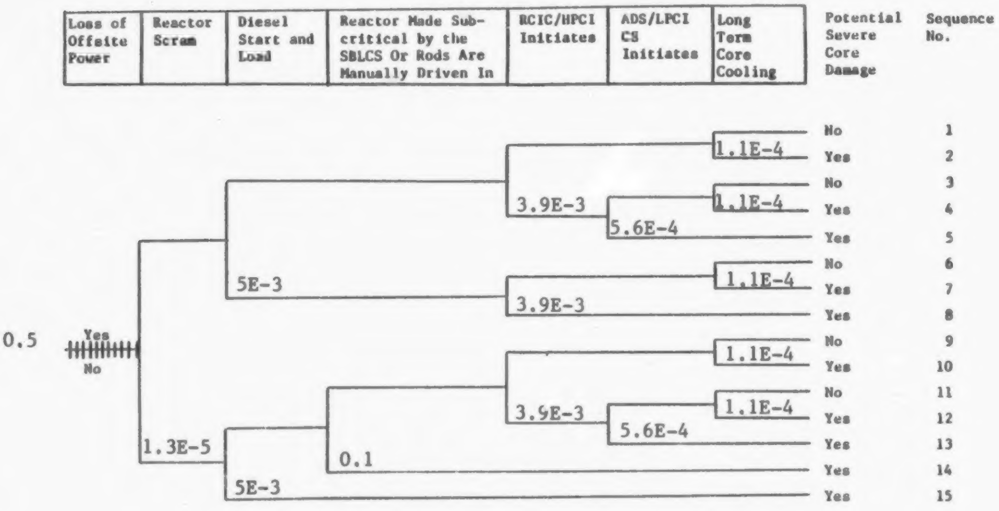

Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 2.9 hrs (1.4E-5)
0.75
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
(*)
(F)
0.5
0.1
2.9E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 5.3E-7 (SC = 63)

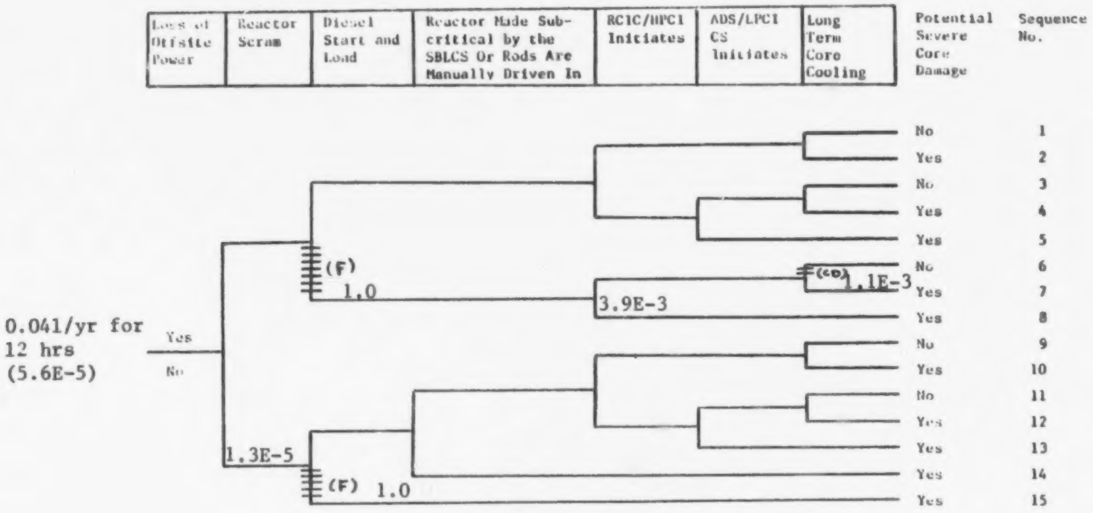
NSIC 139573 — Sequence of Interest for Both Diesel Generators Inoperable at Cook 2

*Not included in mitigation procedures.


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
Yes
No
5E-3
3.9E-3
1.1E-4
1.1E-4
5.6E-4
3.9E-3
1.1E-4
1.3E-5
3.9E-3
1.1E-4
1.1E-4
5.6E-4
0.1
5E-3
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

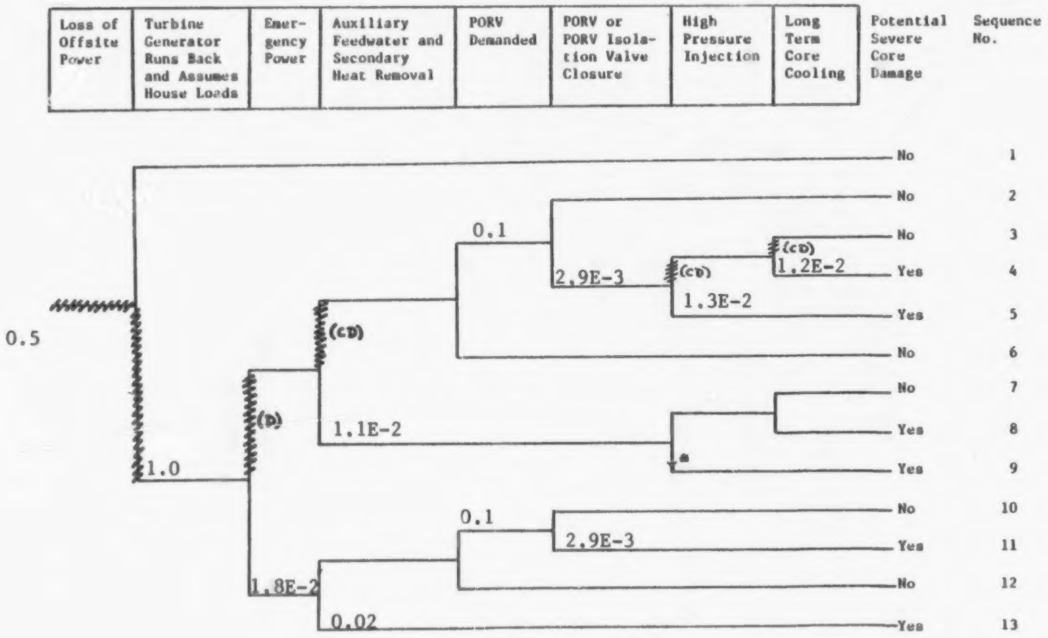
P = 6.7E-5 (SC = 42)

NSIC 140140 — Sequence of Interest for the Loss of Offsite Power at Pilgrim 1


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 12 hrs (5.6E-5)
Yes
No
(F)
1.0
3.9E-3
(CD)
1.1E-3
1.3E-5
(F)
1.0
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 2.6E-7 (SC = 66)

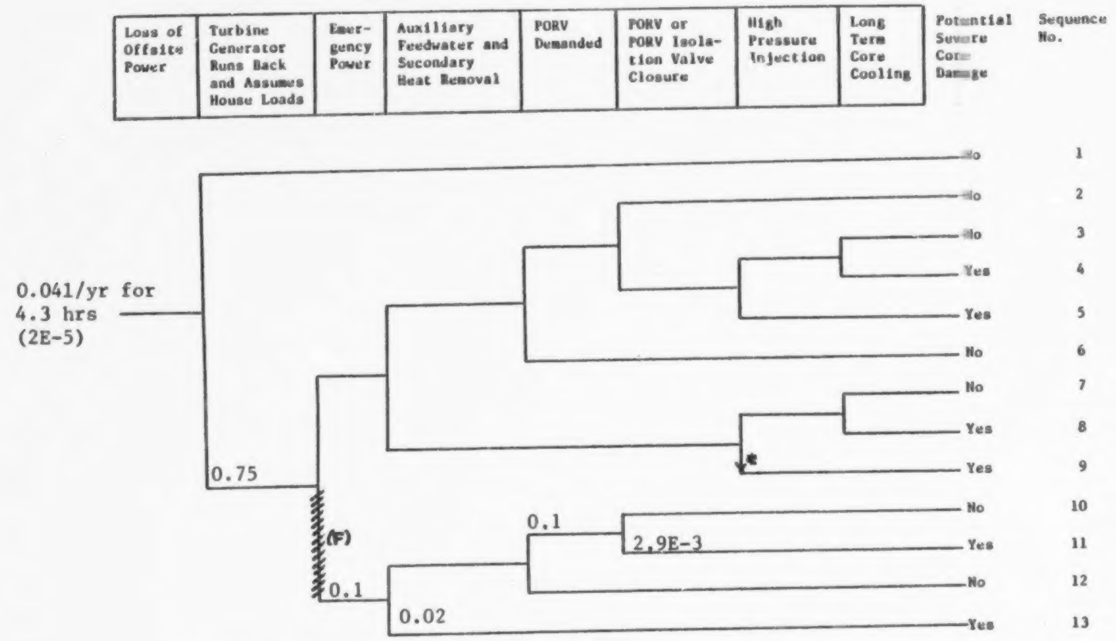
NSIC 140162 – Sequence of Interest for Diesel Generator Fails to Start at Dresden 2


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
(D)
(CD)
0.1
2.9E-3
(CD)
1.3E-2
(CD)
1.2E-2
1.1E-2
*
1.8E-2
0.1
2.9E-3
0.02
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 5.6E-3 (SC = 23)

NSIC 140335 – Sequence of Interest for Loss of Offsite Power and Diesel Generator Failure at Beaver Valley 1

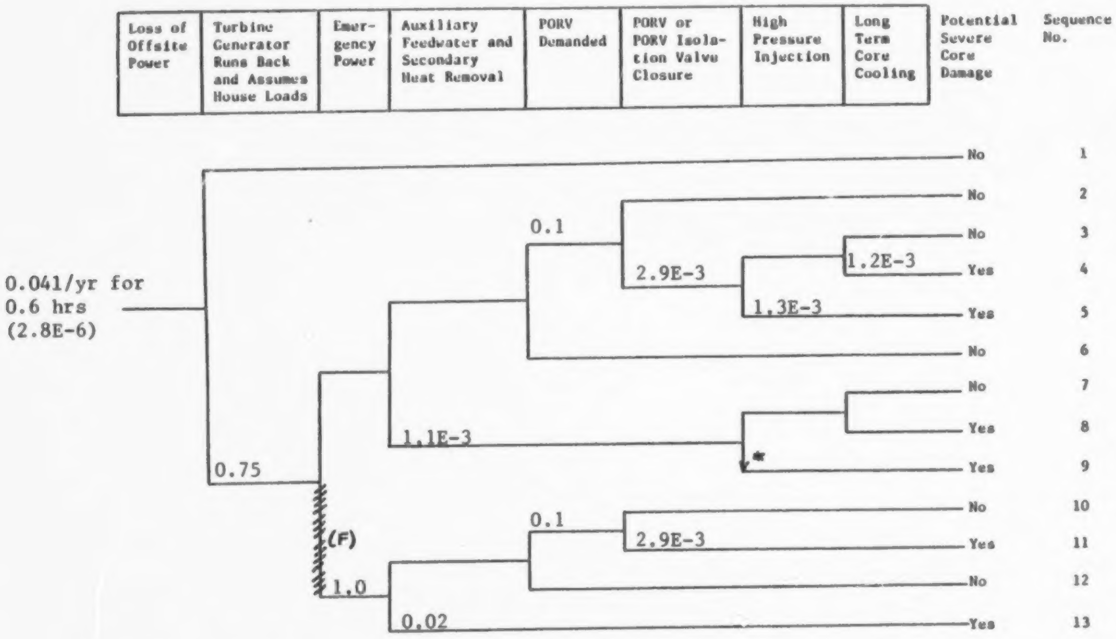
*not included in mitigation procedures


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for
4.3 hrs
(2E-5)
0.75
(F)
0.1
0.02
0.1
2.9E-3
*
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 3.1E-8 x prob. of occurring at power (0.75) = 2.3E-8 (SC = 76)

NSIC 140691 — Sequence of Interest for Two Diesel Generators Unavailable at Beaver Valley 1

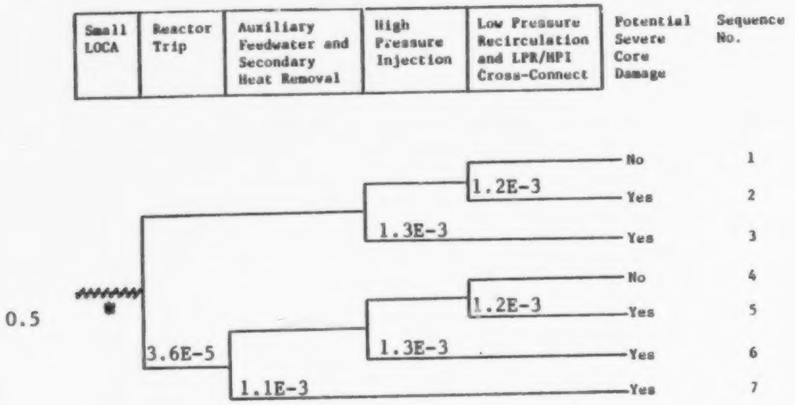
*Not in operating procedures


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for
0.6 hrs
(2.8E-6)
0.75
(F)
1.0
0.02
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
*
0.1
2.9E-3
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 4.3E-8 x prob. of occurring at power (0.75) = 3.2E-8 (SC = 75)

NSIC 140693 — Sequence of Interest for Both Diesel Generators Out of Service at Beaver Valley 1

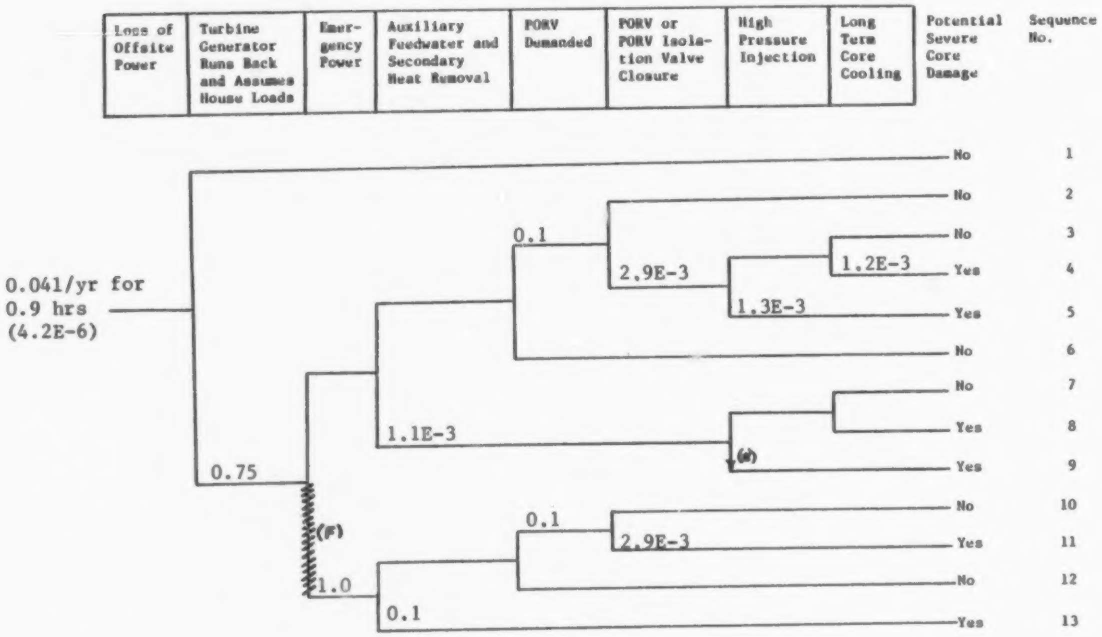
*Not included in operating procedures


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
0.5
*
1.2E-3
1.3E-3
3.6E-5
1.2E-3
1.3E-3
1.1E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 1.25E-3 x prob. of occurring at power (0.75) = 9.4E-4 (SC = 30)

NSIC 141097 — Sequence of Interest for Safety Injection Occurs at Three Mile Island 2

*failure requires operator error of failing to close the PORV isolation valve.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 0.9 hrs (4.2E-6)
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
(*)
0.75
(F)
1.0
0.1
2.9E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 3.2E-7 (SC = 65)

NSIC 141455 — Sequence of Interest for Both Diesel Generators Inoperable Simultaneously at Rancho Seco

*Not included in mitigation procedures.

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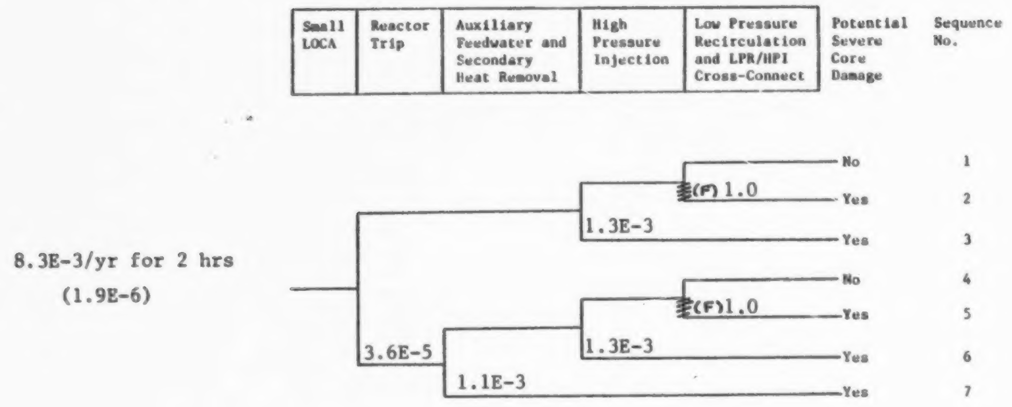
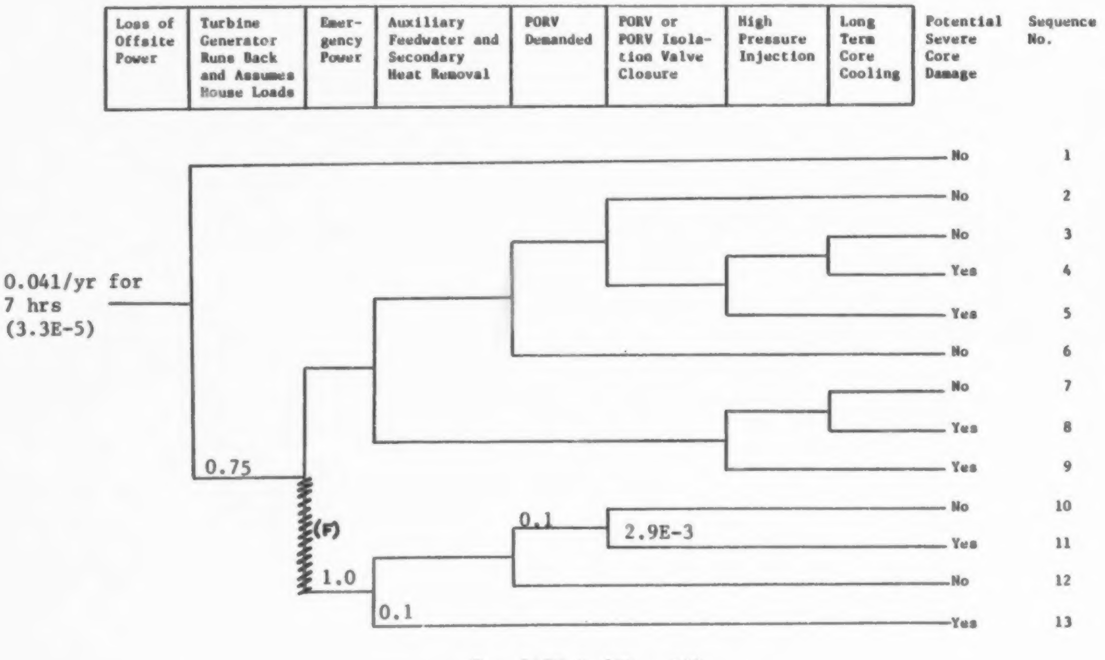
182


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
8.3E-3/yr for 2 hrs
(1.9E-6)
(F) 1.0
1.3E-3
(F)1.0
1.3E-3
3.6E-5
1.1E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

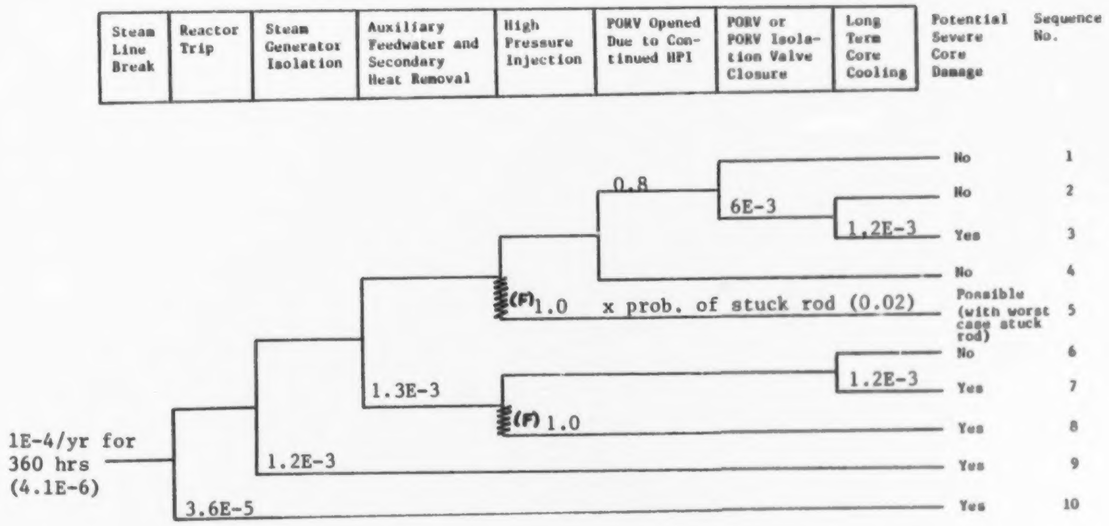
P = 1.9E-6 + addl. cont. (LOFW), 3.8E-8 = 1.9E-6 x
prob. of occurring at hot shutdown (0.1) = 1.9E-7 (SC = 67)

NSIC 141523 — Sequence of Interest for Both LPSI Pumps Airbound at Calvert Cliffs 2


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for
7 hrs
(3.3E-5)
0.75
(F)
1.0
0.1
2.9E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

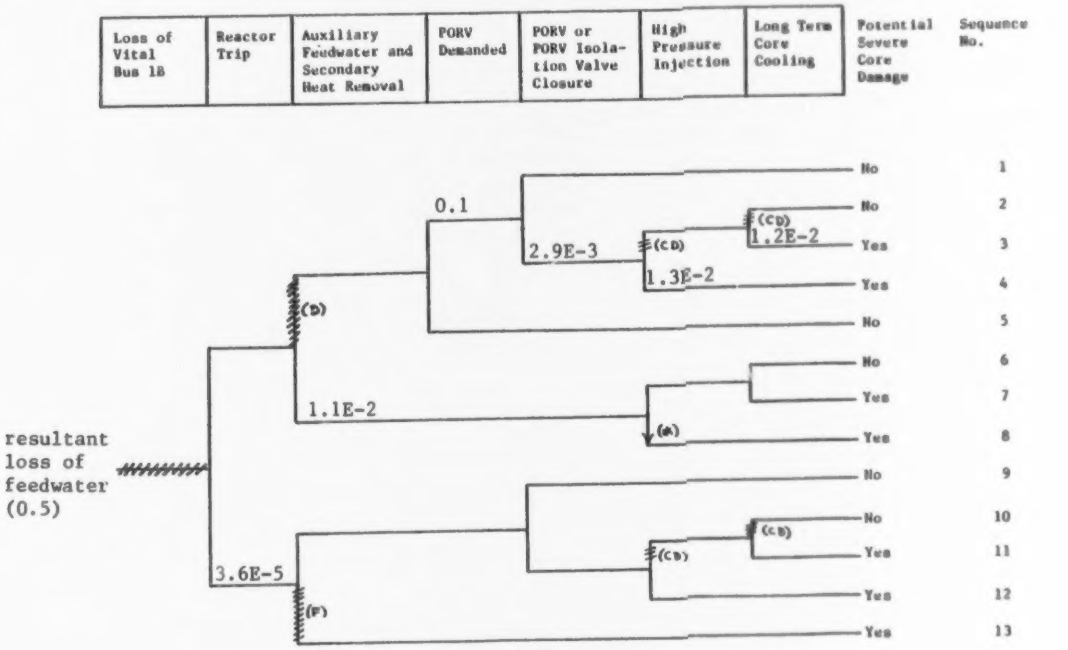
P = 2.5E-6 (SC = 56)

NSIC 141706 — Sequence of Interest for Loss of Emergency Power at Rancho Seco


Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1E-4/yr for 360 hrs (4.1E-6)
0.8
6E-3
1.2E-3
(F) 1.0
x prob. of stuck rod (0.02)
1.3E-3
1.2E-3
(F) 1.0
1.2E-3
3.6E-5
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

P = 8.7E-8 x prob. of occurring at power (0.75) = 6.5E-8 (SC = 72)

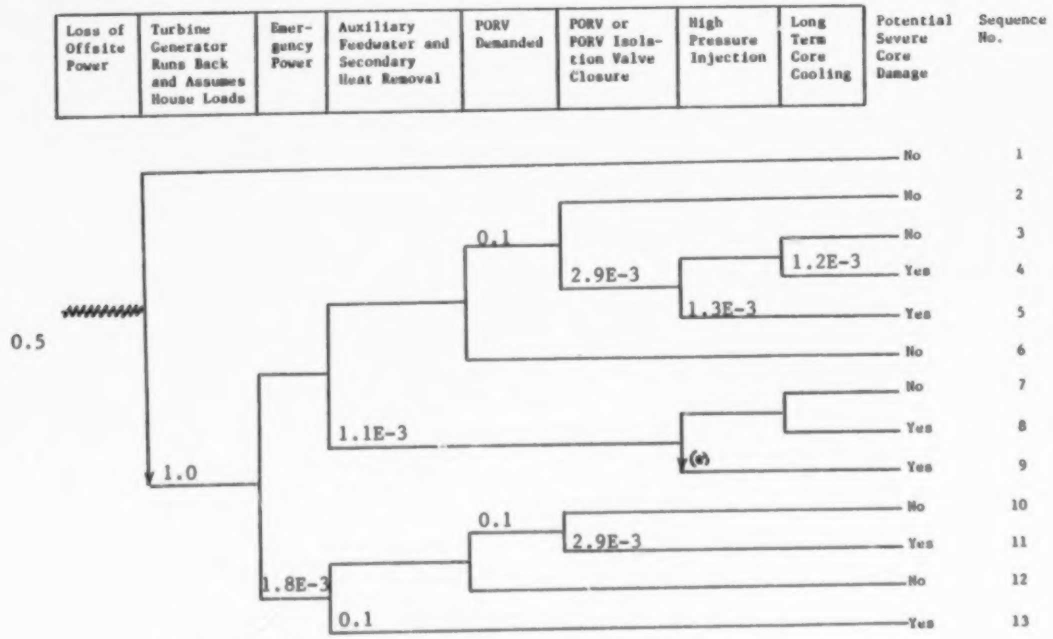
NSIC 142329 — Sequence of Interest for Blockage Found in BIT Discharge Line at Indian Point 2


Loss of Vital Bus 1B
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
resultant loss of feedwater (0.5)
0.1
2.9E-3
(CD)
1.3E-2
(CD)
1.2E-2
(D)
1.1E-2
(*)
3.6E-5
(F)
(CD)
(CD)
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

P = 5.5E-3 (SC = 23)

NSIC 142462 — Sequence of Interest for Loss of a Vital Instrument Bus Initiates a Reactor Trip at Salem 1

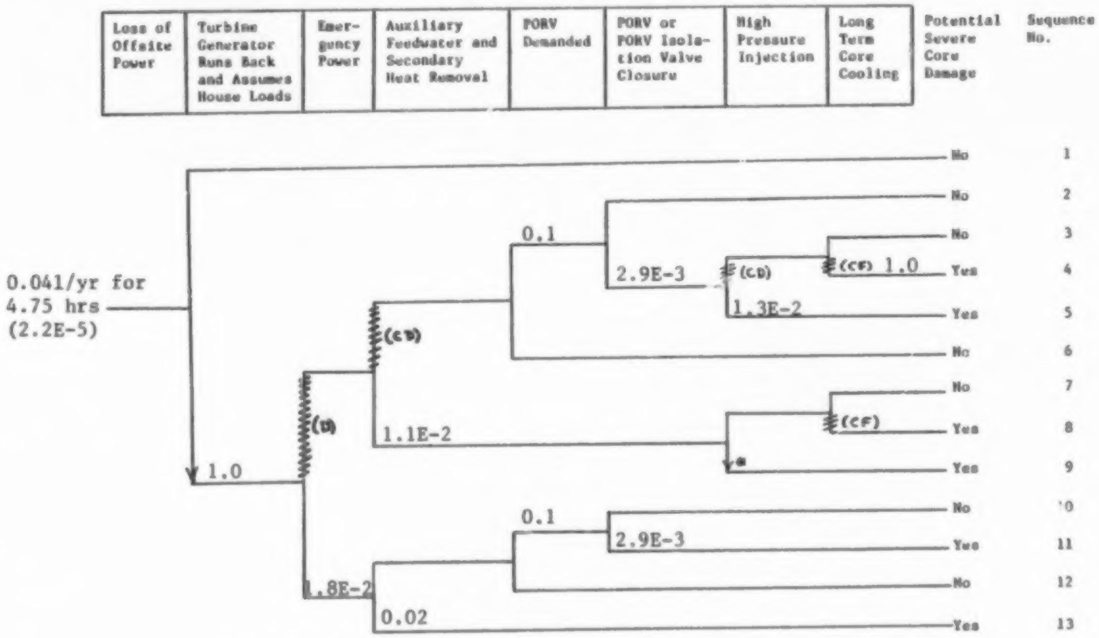
*Not included in mitigation procedures.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
1.1E-3
0.1
2.9E-3
1.3E-3
1.2E-3
(*)
1.8E-3
0.1
2.9E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 6.4E-4 x prob. of occurring at power (0.75) = 4.8E-4 (SC = 33)

NSIC 143219 -- Sequence of Interest for Loss of Offsite Power at Indian Point 3

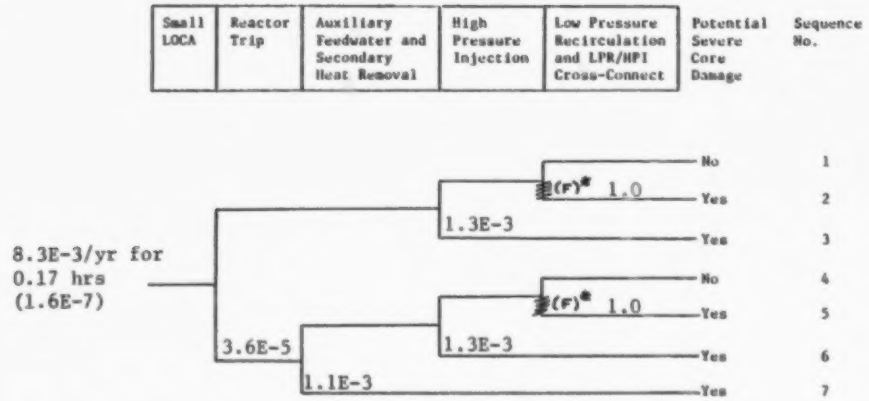
*not included in mitigation procedures.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 4.75 hrs (2.2E-5)
1.0
(D)
(CD)
1.1E-2
0.1
2.9E-3
(CD)
1.3E-2
(CF) 1.0
(CF)
*
1.8E-2
0.02
0.1
2.9E-3
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 2.6E-7 x prob. of occurring at power (0.75) = 2E-7 (SC = 67)

NSIC 143255 - Sequence of Interest for 2 of 3 Diesel Generators Fail to Reach Rated Speed at Salem 1

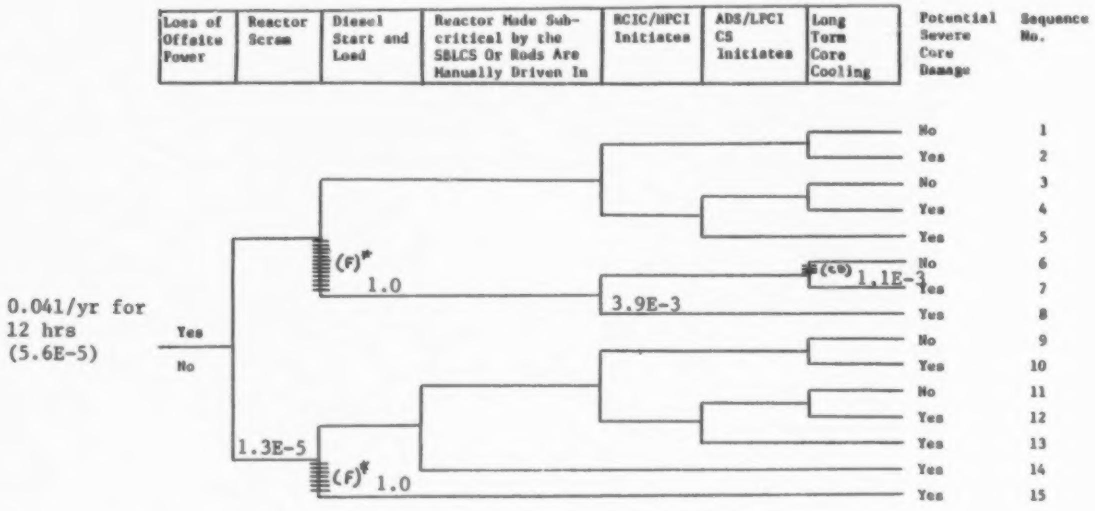
* not included in mitigation procedures.


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
8.3E-3/yr for 0.17 hrs (1.6E-7)
(F)* 1.0
1.3E-3
(F)* 1.0
1.3E-3
3.6E-5
1.1E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 1.6E-7 + addl. cont. (LOFW), 3.2E-9 = 1.63E-7 (SC = 68)

NSIC 143296 – Sequence of Interest for Both RWST Outlet Valves Inadvertantly Closed at Maine Yankee

*success requires operator detection of closed valves and their re-opening prior to LPI pump failure from cavitation.


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Sub-critical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 12 hrs (5.6E-5)
Yes
No
(F)* 1.0
3.9E-3
(CS) 1.1E-3
1.3E-5
(F)* 1.0
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 2.6E-7 (SC = 66)

NSIC 143533 – Sequence of Interest for Diesel Generator Load Cycles at Brunswick 1

*A degraded state of emergency power may be obtained by proper load shedding.

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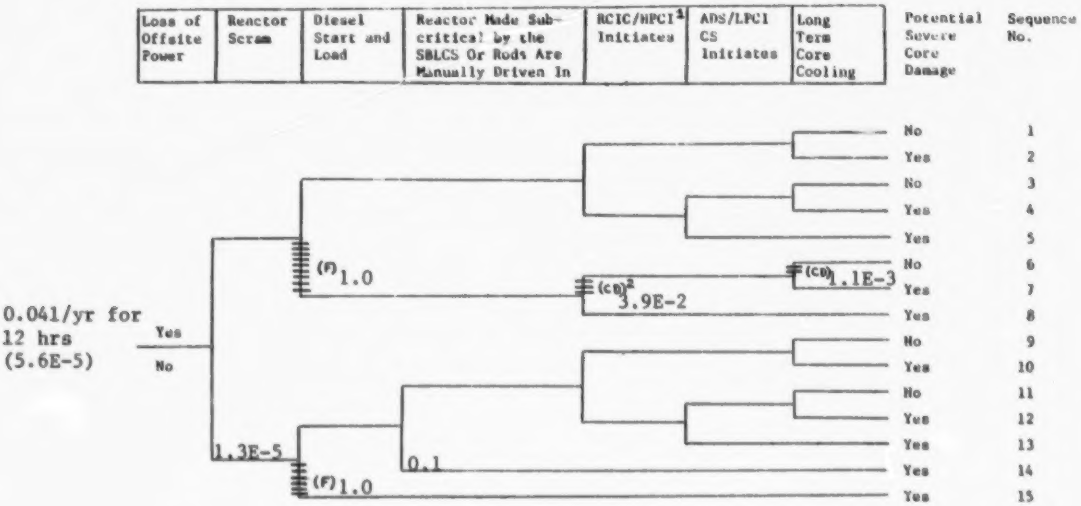
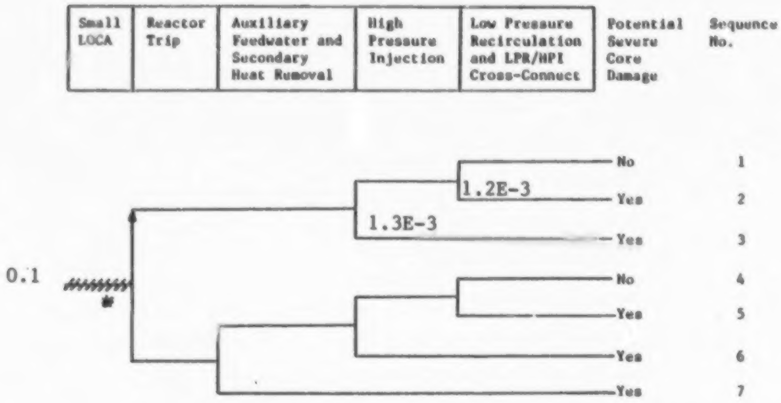

Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI¹ Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 12 hrs (5.6E-5)
Yes
No
(F) 1.0
(CD)² 3.9E-2
(CD) 1.1E-3
1.3E-5
(F) 1.0
0.1
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 2.2E-6 + addl. cont. (LOFW, LOCA, MSLB), 7.5E-6 = 9.7E-6 (SC = 50)

NSIC 144187 – Sequence of Interest for Diesel Generator Found Inoperable at Millstone 1

[1] Millstone 1 utilizes FWCI and IC instead of HPCI

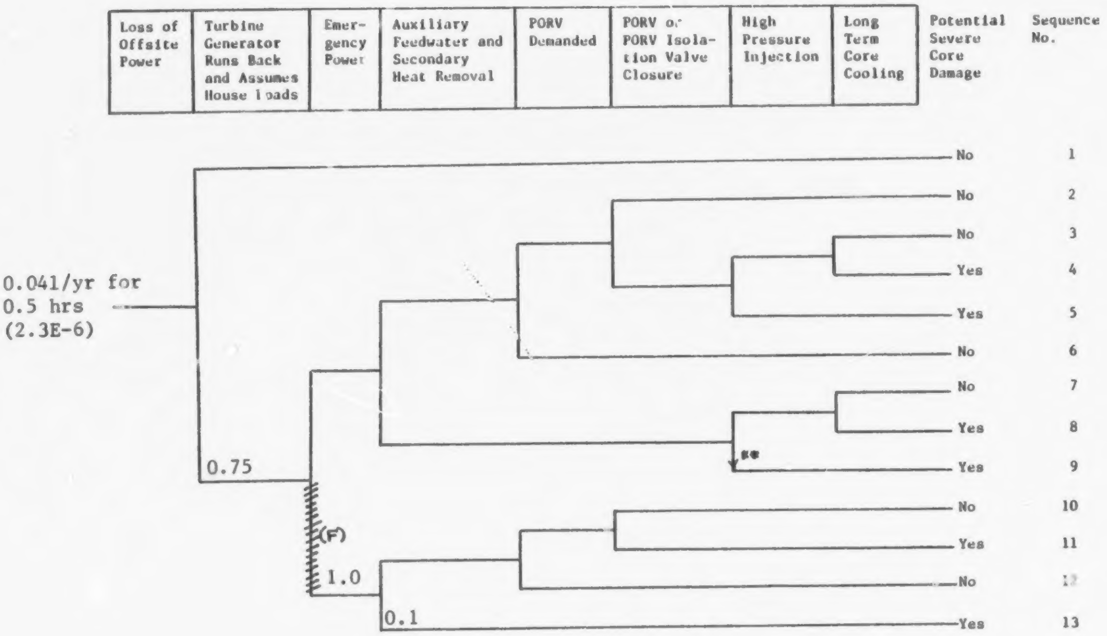
[2] Success of the FWCI system requires success of gas turbine and success of the IC


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
0.1
*
1.2E-3
1.3E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 2.5E-4 x prob. of occurring at hot shutdown
or at power (0.75) = 1.9E-4 (SC = 37)

NSIC 145209 – Sequence of Interest for Both Power Operated Relief Valves Open During Troubleshooting at Fort Calhoun 1

*initiating event requires operator failure to close PORV isolation valves.



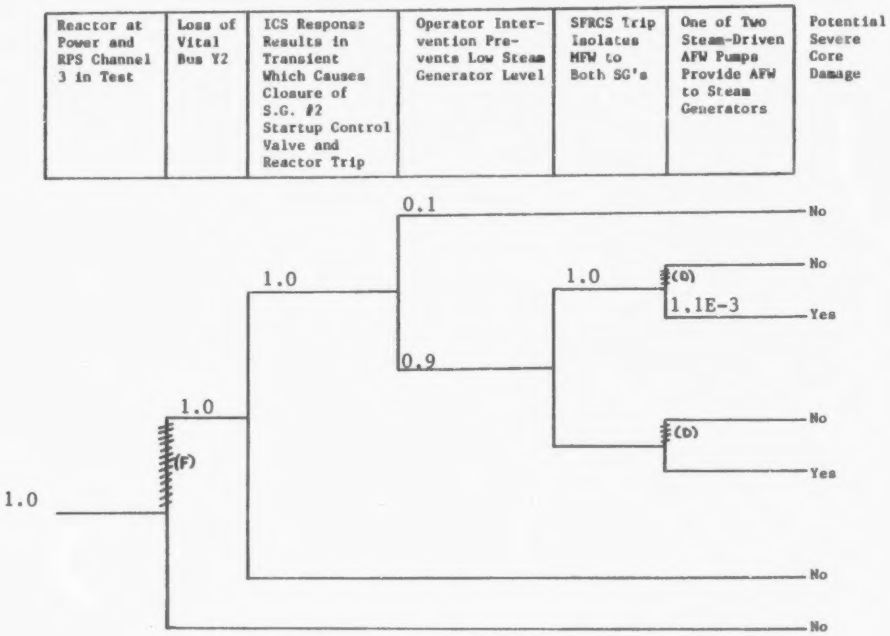
Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 0.5 hrs (2.3E-6)
0.75
(F)
1.0
0.1
**
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1.7E-7 (SC = 68)

NSIC 146540 — Sequence of Interest for Both Diesel Generators Out of Service at Kewaunee

*sucess requires manual opening of valves associated with turbine driven AFW pump.

**not included in mitigation procedures.

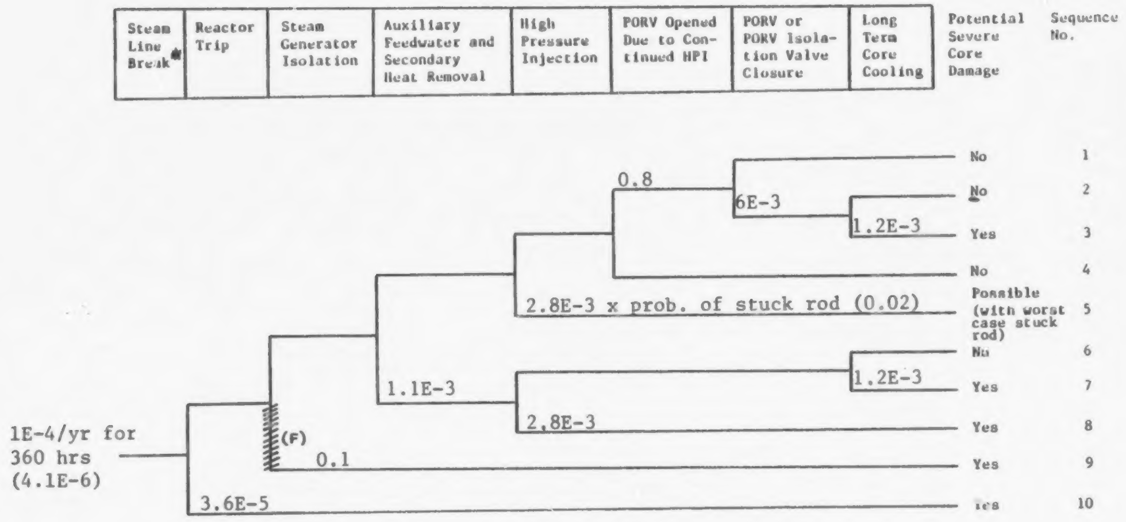


Reactor at Power and RPS Channel 3 in Test
Loss of Vital Bus Y2
ICS Response Results in Transient Which Causes Closure of S.G. #2 Startup Control Valve and Reactor Trip
Operator Intervention Prevents Low Steam Generator Level
SFRCS Trip Isolates MFW to Both SG's
One of Two Steam-Driven AFW Pumps Provide AFW to Steam Generators
Potential Severe Core Damage
1.0
(F)
1.0
1.0
0.1
0.9
1.0
(D)
1.1E-3
(D)
No
No
Yes
No
Yes
No
No

P = 9.9E-4 (SC = 30)

NSIC 146744 - Sequence of Interest for Power Loss to Vital Bus Results in Reactor Scram at Davis-Besse

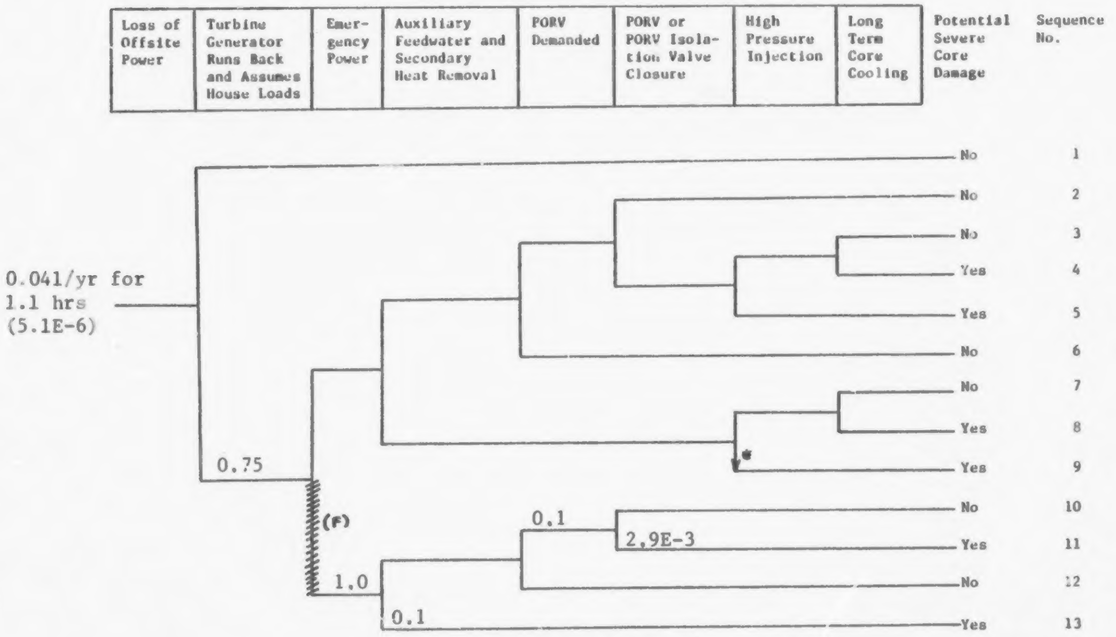
[redacted]


Steam Line Break*
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1E-4/yr for 360 hrs (4.1E-6)
0.8
6E-3
1.2E-3
2.8E-3 x prob. of stuck rod (0.02)
1.1E-3
1.2E-3
2.8E-3
(F)
0.1
3.6E-5
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

P = 4.1E-7 (SC = 64)

NSIC 147223 — Sequence of Interest for Feedwater Block Valve Fails to Close at Crystal River 3

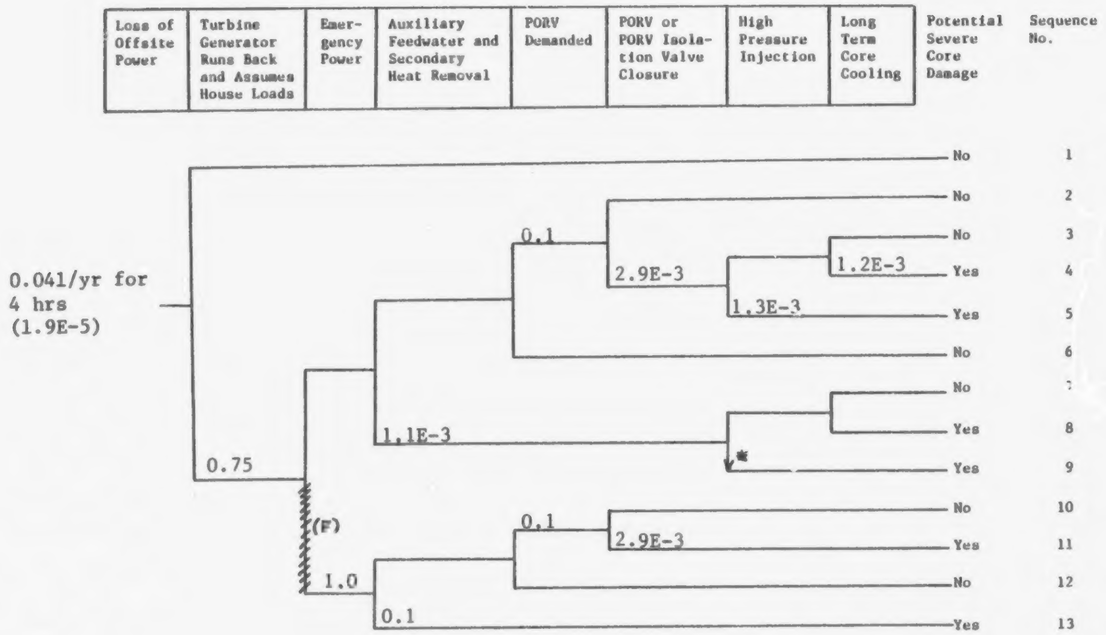
*"A" Steam Generator Steam Line


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 1.1 hrs (5.1E-6)
0.75
(F)
*
0.1
2.9E-3
1.0
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 3.8E-7 (SC = 64)

NSIC 147383 — Sequence of Interest for Both Diesel Generators Inoperable Twice at Cook 1

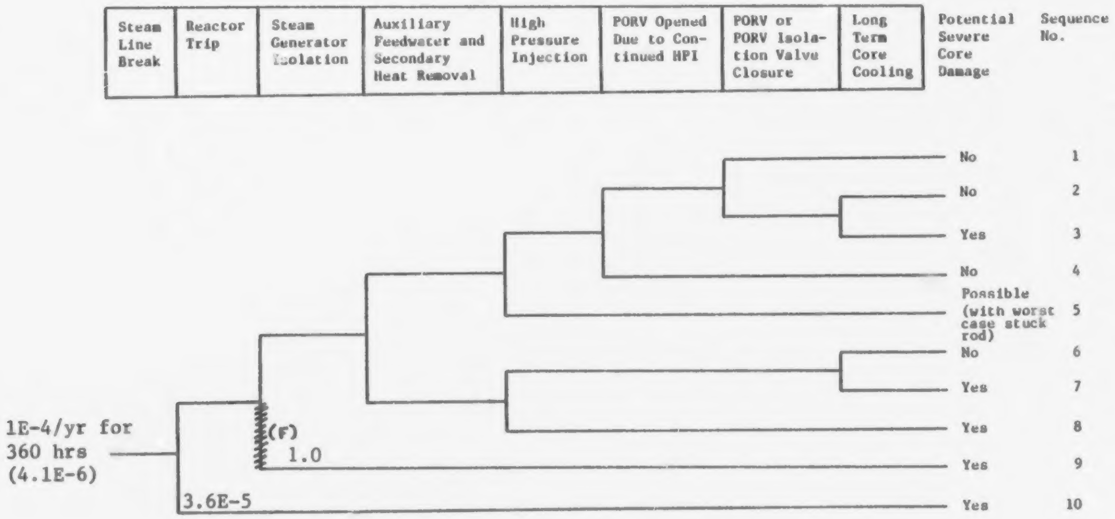
*Not included in mitigation procedures.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 4 hrs (1.9E-5)
0.75
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
*
(F)
1.0
0.1
2.9E-3
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1.4E-6 (SC = 59)

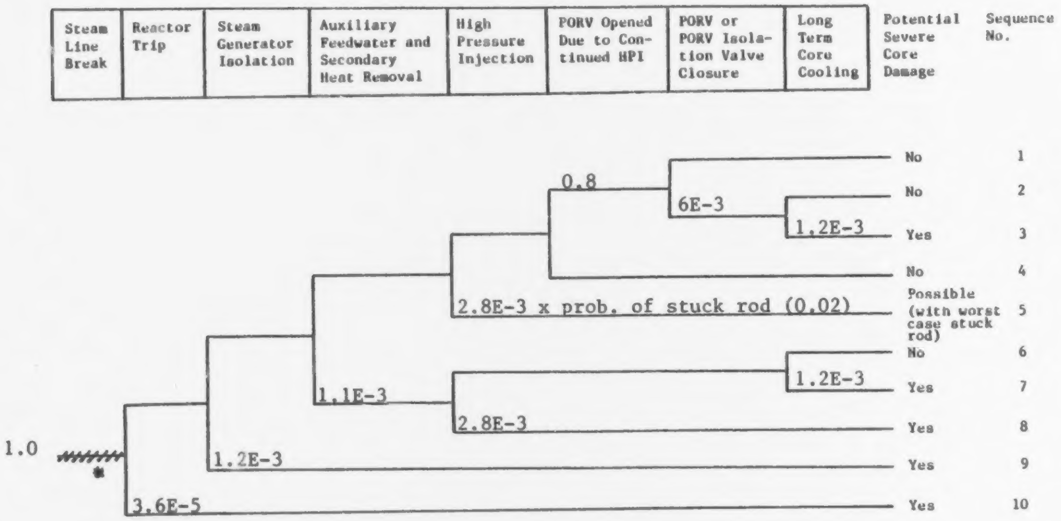
NSIC 147399 — Sequence of Interest for Both Diesel Generators Unavailable at Kewaunee

*Not included in operating procedures


Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1E-4/yr for 360 hrs (4.1E-6)
(F)
1.0
3.6E-5
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

P = 4.1E-6 (SC = 54)

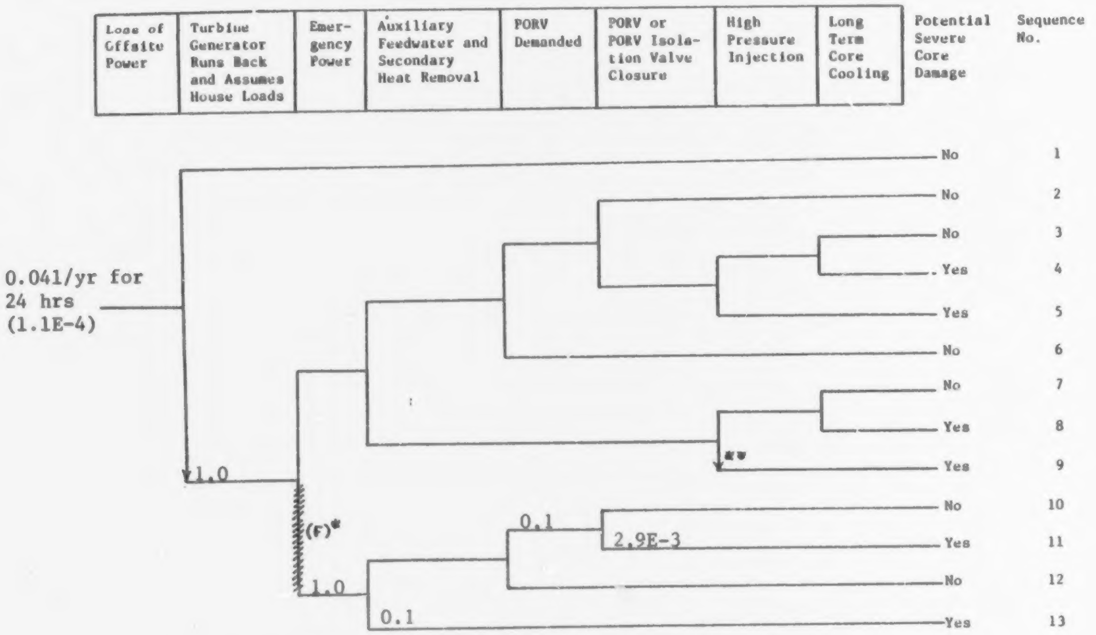
NSIC 147400 — Sequence of Interest for Both Main Steam Stop Valves Fail to Close at Point Beach 2


Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
*
3.6E-5
1.2E-3
1.1E-3
2.8E-3
2.8E-3 x prob. of stuck rod (0.02)
0.8
6E-3
1.2E-3
1.2E-3
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

P = 1.3E-3 (SC = 29)

NSIC 148764 — Sequence of Interest for Steam Dump Valves Fail to Close Following Load Rejection at Beaver Valley 1

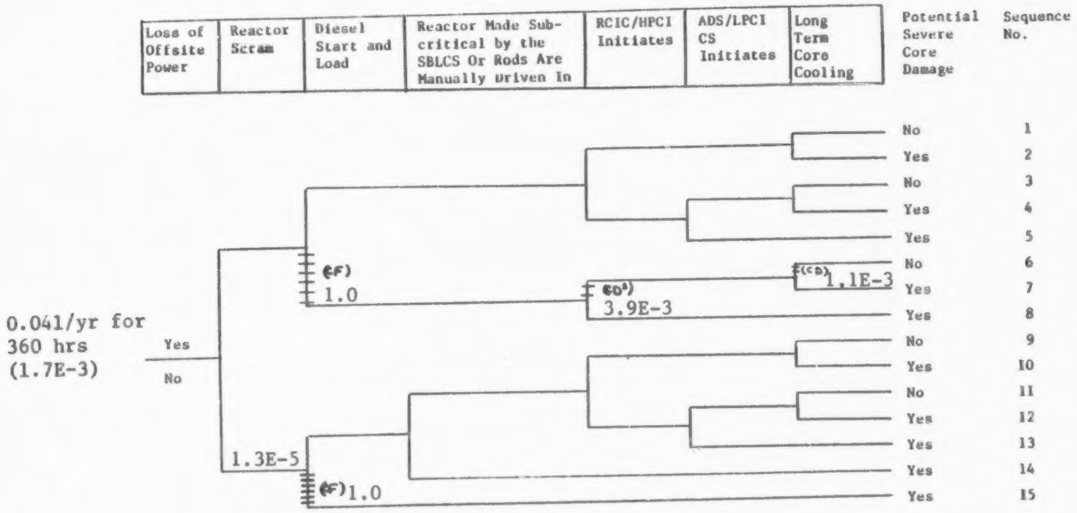
*small


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 24 hrs (1.1E-4)
1.0
(F)*
1.0
0.1
0.1
2.9E-3
**
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 1.1E-5 (SC = 50)

NSIC — 148892 -- Sequence of Interest for Diesel Generator Sequencer Found in Test Mode at Farley 1

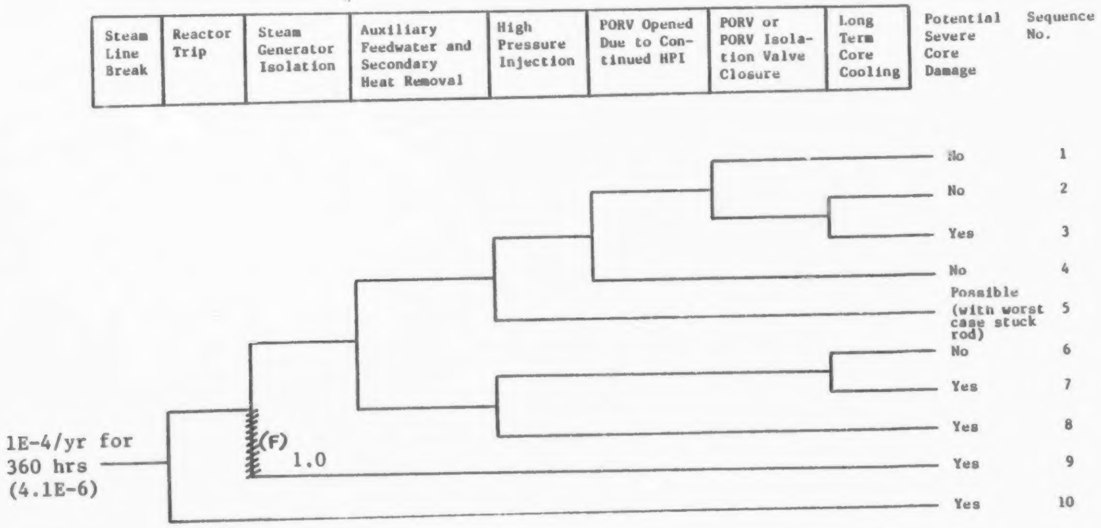
*success requires operator action to transfer loads to a smaller, river water pump diesel generator.
**not included in mitigation procedures.


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 360 hrs (1.7E-3)
Yes
No
(F) 1.0
(CD¹) 3.9E-3
(CD) 1.1E-3
1.3E-5
(F) 1.0
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 8.4E-6 + addl. cont. (LOFW), 2.6E-5 = 3.4E-5 (SC = 45)

NSIC 149230 — Sequence of Interest of Both Emergency Service Water Systems Inoperable at Arnold

[1] RCIC/HPCI room cooling units served by ESWS. Both RCIC & HPCI turbine isolate at 200°F. The possiblity of a failed state rather than just degraded exists.

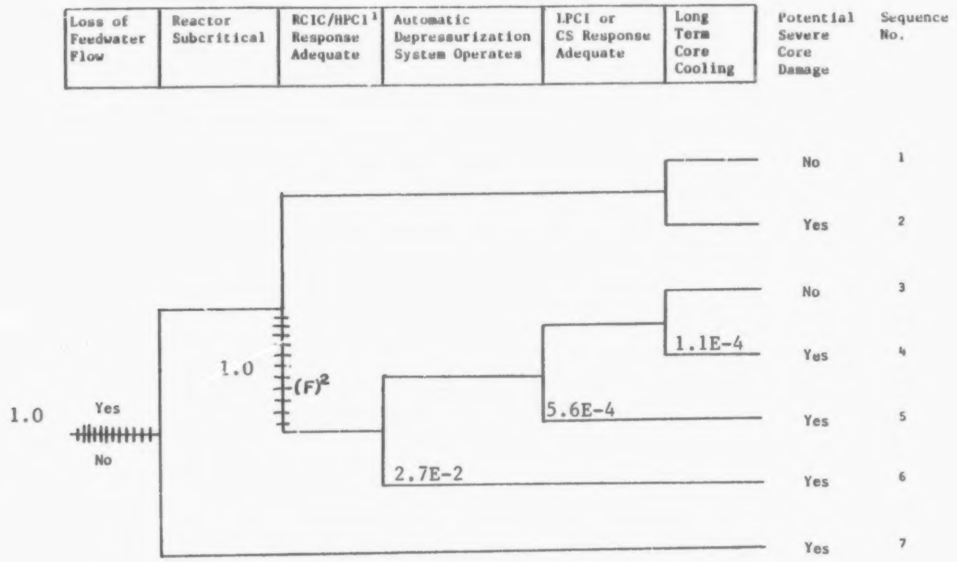

Steam Line Break
Reactor Trip
Steam Generator Isolation
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
PORV Opened Due to Continued HPI
PORV or PORV Isolation Valve Closure
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1E-4/yr for 360 hrs (4.1E-6)
(F) 1.0
No 1
No 2
Yes 3
No 4
Possible (with worst case stuck rod) 5
No 6
Yes 7
Yes 8
Yes 9
Yes 10

P = 4.1E-6 x prob. of event occurring at power (0.75) = 3.1E-6 (SC = 55)

NSIC 149250 — Sequence of Interest for Two Main Steam Isolation Valves Fail to Close at Trojan

BEST DOCUMENT AVAILABLE

[redacted]

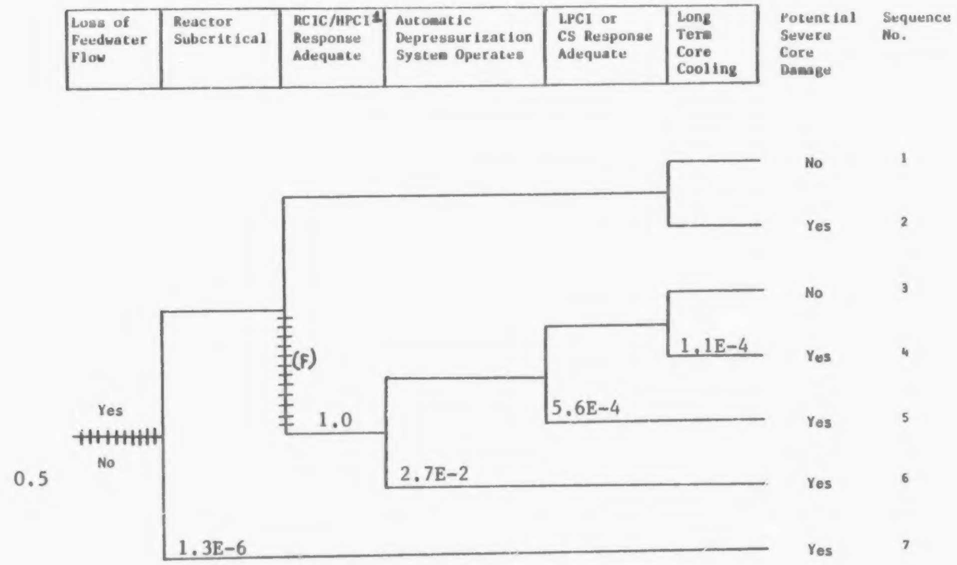

Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI[1] Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
Yes
No
1.0
(F)[2]
2.7E-2
5.6E-4
1.1E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 2.77E-2 (SC = 16)

NSIC 149450 – Sequence of Interest for a Loss of Feedwater Flow at Oyster Creek

[1] Oyster Creek utilizes Isolation condensers rather than RCIC

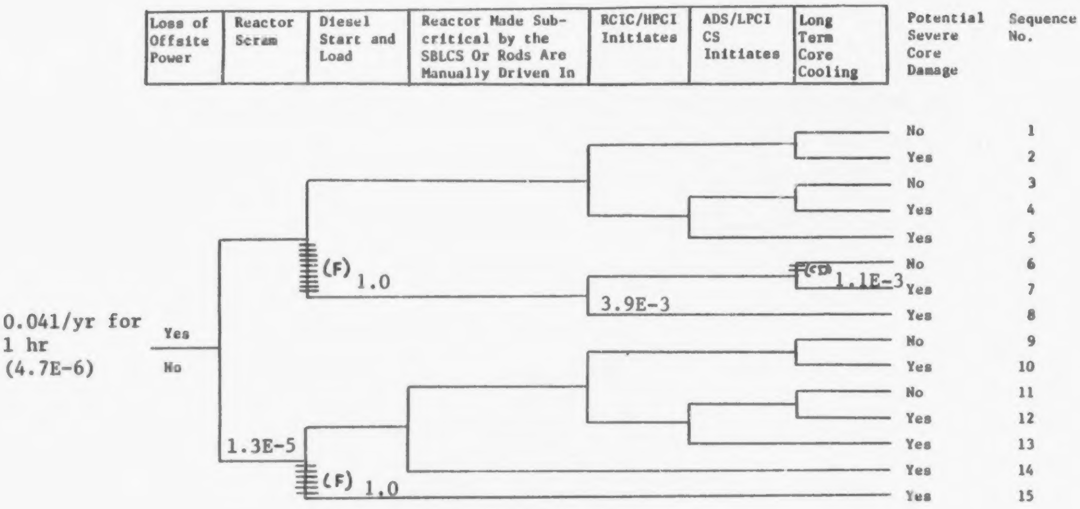
[2] Success requires proper operation of either FWCT or IC.


Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI[1] Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
Yes
No
(F)
1.0
2.7E-2
5.6E-4
1.1E-4
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 1.38E-2 (SC = 19)

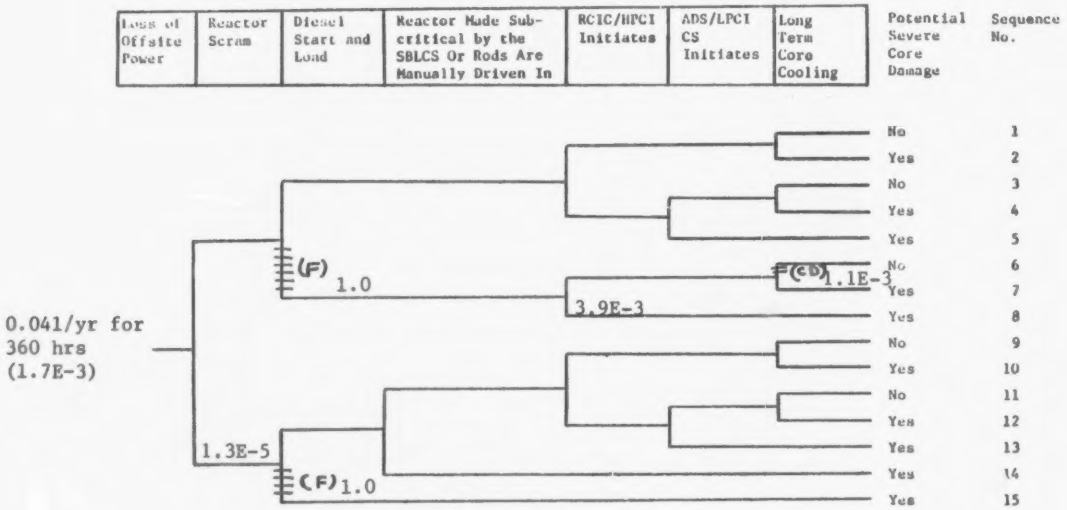
NSIC 149961 – Sequence of Interest for HPCI Fails to Start When the Turbine Stop Valve Fails to Open at Hatch 2

[1] RCIC was out of service.


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Sub-critical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 1 hr (4.7E-6)
Yes
No
(F) 1.0
1.3E-5
(F) 1.0
3.9E-3
(CD) 1.1E-3
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 2.1E-8 (SC = 77)

NSIC 149962 — Sequence of Interest for Diesel Generator Unable to Carry Load at Hatch 1

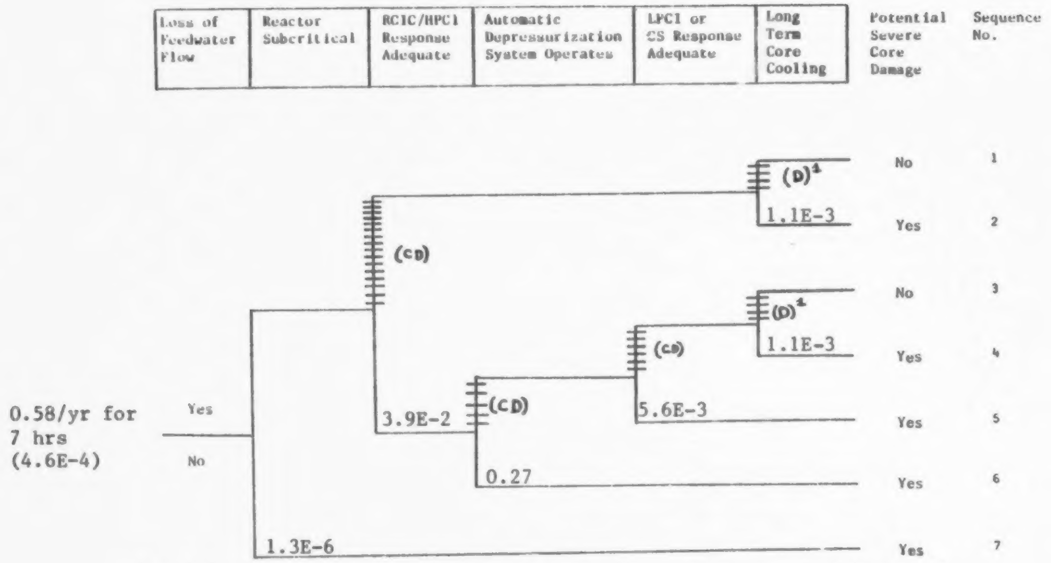

Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Sub-critical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 360 hrs (1.7E-3)
(F) 1.0
1.3E-5
(F) 1.0
3.9E-3
(CD) 1.1E-3
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 7.8E-6 (SC = 51)

NSIC 150051 — Sequence of Interest for Failure of Two Diesel Generators at Dresden 2

BEST DOCUMENT AVAILABLE

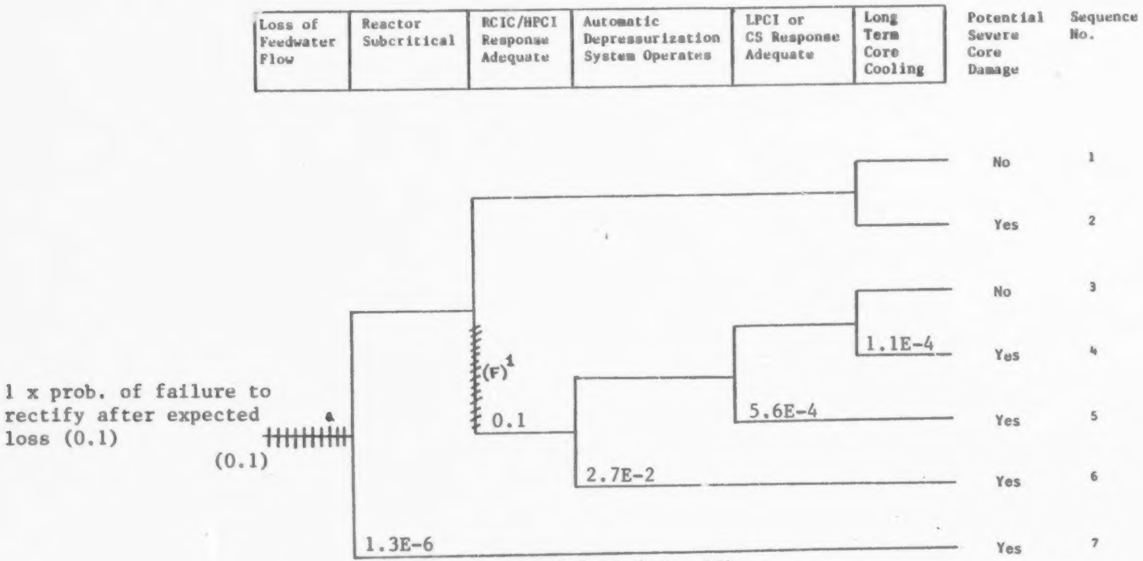
[redacted]


Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.58/yr for 7 hrs (4.6E-4)
Yes
No
(CD)
3.9E-2
(CD)
0.27
(CD)
5.6E-3
(D)1
1.1E-3
(D)1
1.1E-3
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 5.5E-6 + addl. cont. (LOOP, LOCA, MSLB), 2.2E-5 = 2.7E-5 (SC = 46)

NSIC 150271 – Sequence of Interest of Both RHR Service Water Pumps Inoperable at Brunswick 2

[1] For success the operator must rack the pumps backin within 2-24 hours.

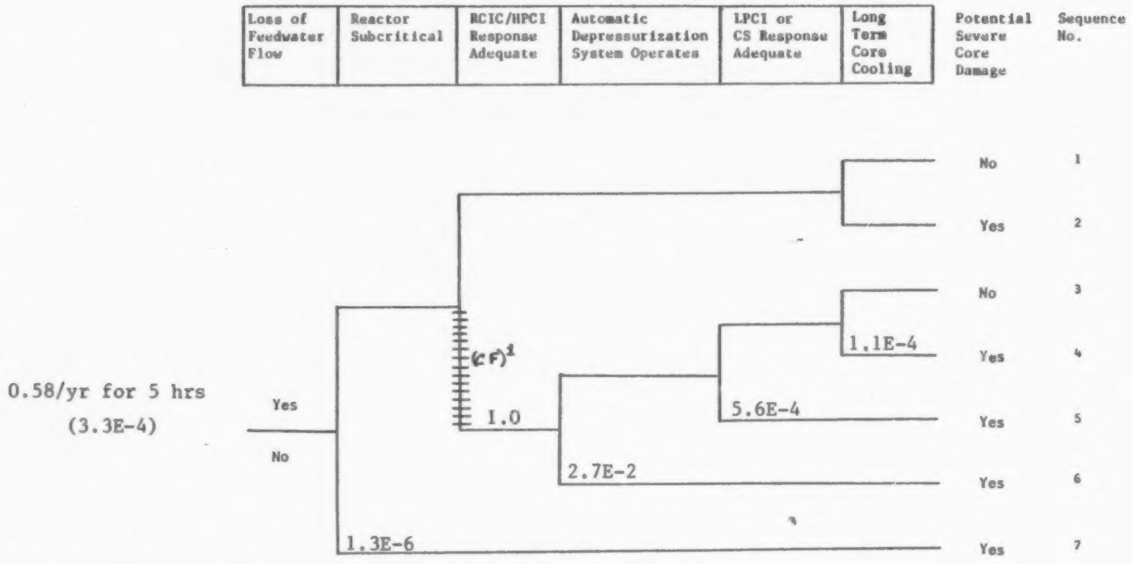

Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1 x prob. of failure to rectify after expected loss (0.1)
(0.1)
2
(F)1
0.1
2.7E-2
5.6E-4
1.1E-4
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 2.8E-4 (SC = 36)

NSIC 150499 – Sequence of Interest for RCIC and HPCI Isolate Following a Reactor Scram at Hatch 2

[1] Success requires the operator to reset HPCI and/or RCIC.

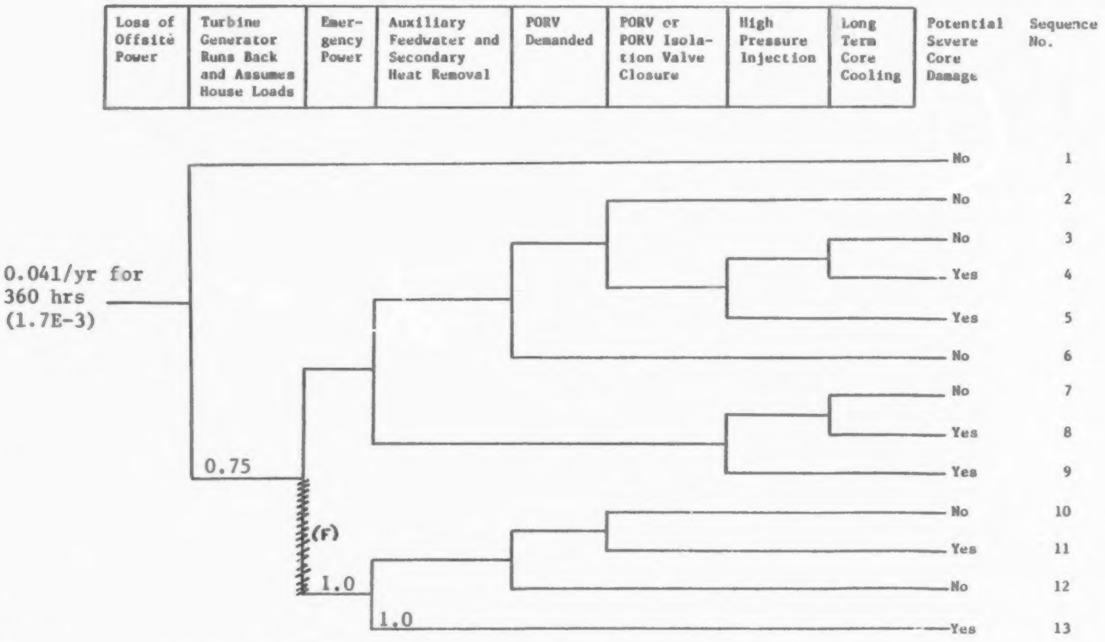
[2] Loss of feedwater is presumed.


Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.58/yr for 5 hrs
(3.3E-4)
Yes
No
(CF)1
1.0
1.1E-4
5.6E-4
2.7E-2
1.3E-6
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7

P = 1.1E-6 + addl. cont. (LOOP, LOCA, MSLB), 9.2E-6 = 1.03E-5 (SC = 50)

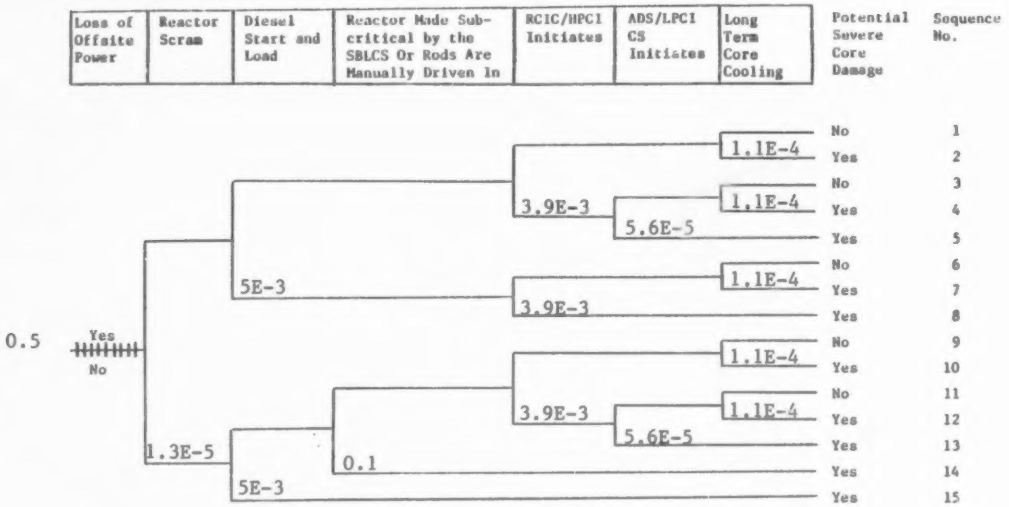
NSIC 150742 — Sequence of Interest of Main Stack Sampling System Lost at Peach Bottom 2

[1] RCIC and HPCI were probably operable through a manual bus transfer and manual initiation.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 360 hrs
(1.7E-3)
0.75
(F)
1.0
1.0
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

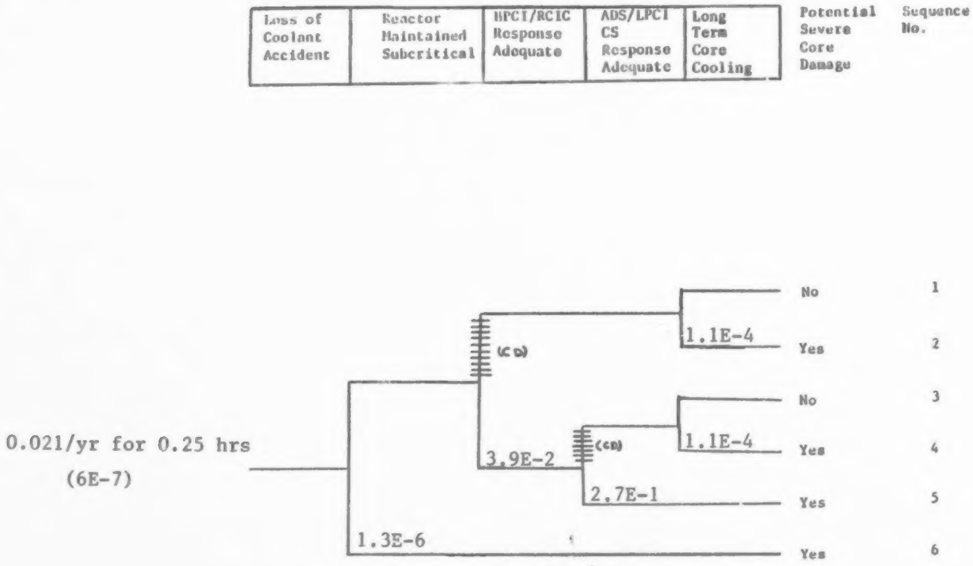
P = 1.3E-3 x prob. of occurring at power (0.75) = 9.8E-4 (SC = 30)

NSIC 150882 — Sequence of Interest for Failure of Both Diesel Generators During Testing at Crystal River 3


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Subcritical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
Yes
No
1.3E-5
5E-3
5E-3
0.1
3.9E-3
3.9E-3
3.9E-3
5.6E-5
5.6E-5
1.1E-4
1.1E-4
1.1E-4
1.1E-4
1.1E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 6E-5 (SC = 42)

NSIC 150943 — Sequence of Interest of the Loss of Offsite Power at Pilgrim 1

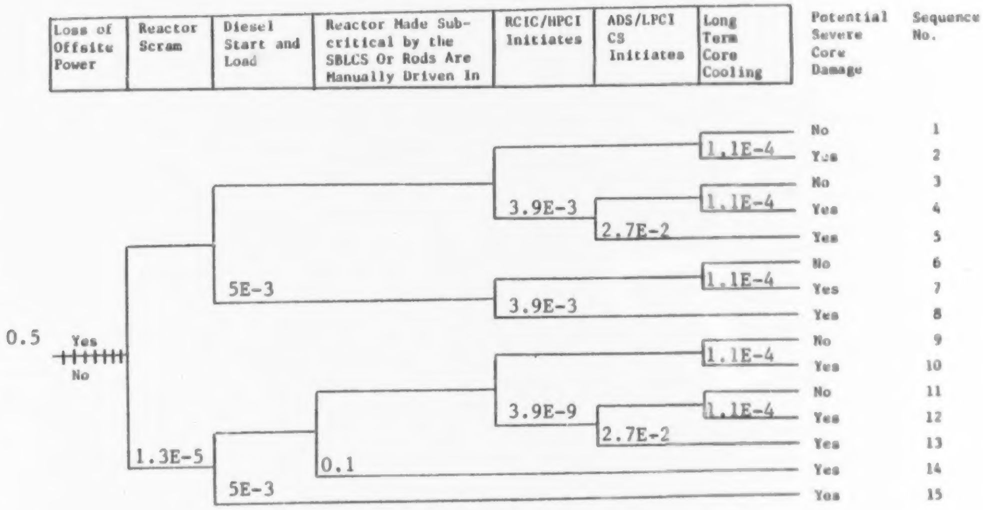

Loss of Coolant Accident
Reactor Maintained Subcritical
HPCI/RCIC Response Adequate
ADS/LPCI CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.021/yr for 0.25 hrs
(6E-7)
1.3E-6
3.9E-2
2.7E-1
(CD)
(CD)
1.1E-4
1.1E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6

P = 6.3E-9 + addl. cont. (LOFW, LOOP, MSLB), 8.8E-8 = 9.5E-8 (SC = 70)

NSIC 151433 — Sequence of Interest for Incorrect RHR Service Water Breakers Racked Out at Brunswick 2

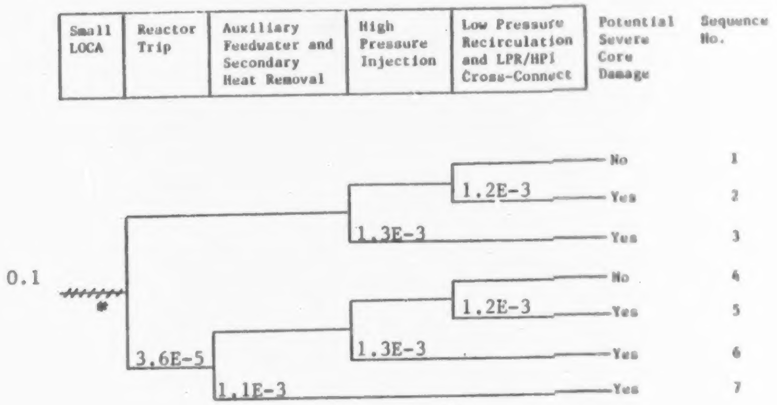
[1] For success the operator must rack the pumps back in within 2 to 24 hours.

[redacted]


Loss of Offsite Power
Reactor Scram
Diesel Start and Load
Reactor Made Sub-critical by the SBLCS Or Rods Are Manually Driven In
RCIC/HPCI Initiates
ADS/LPCI CS Initiates
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
Yes
No
1.3E-5
5E-3
5E-3
0.1
3.9E-3
3.9E-3
3.9E-9
2.7E-2
2.7E-2
1.1E-4
1.1E-4
1.1E-4
1.1E-4
1.1E-4
No 1
Yes 2
No 3
Yes 4
Yes 5
No 6
Yes 7
Yes 8
No 9
Yes 10
No 11
Yes 12
Yes 13
Yes 14
Yes 15

P = 6E-5 (SC = 42)

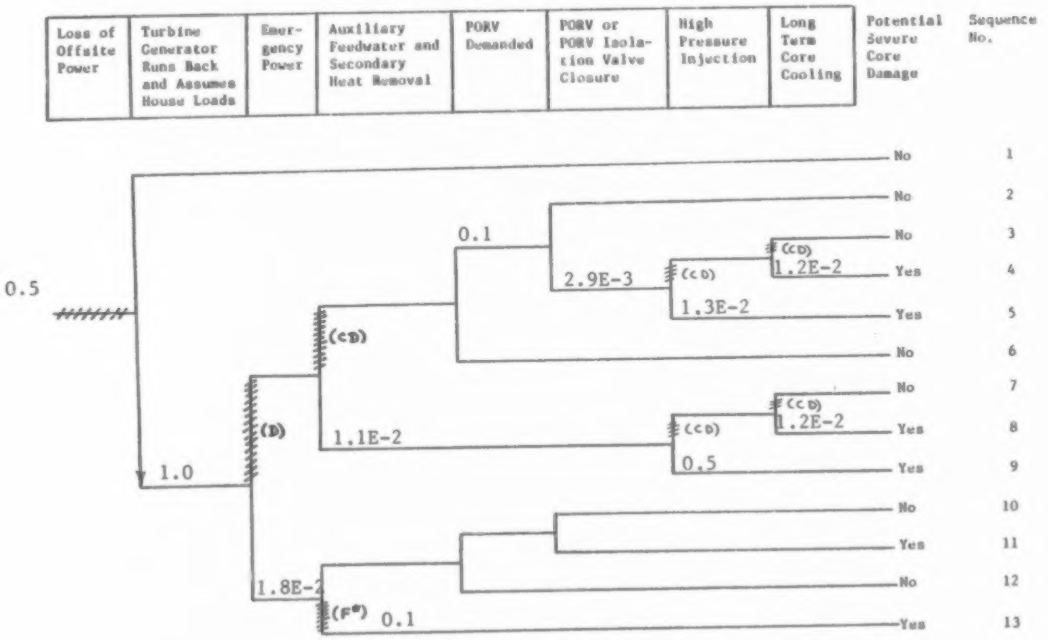
NSIC 151635 – Sequence of Interest for the Loss of Offsite Power at Pilgrim 1


Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
0.1
*
3.6E-5
1.1E-3
1.3E-3
1.3E-3
1.2E-3
1.2E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 2.5E-4 (SC = 36)

NSIC 152123 – Sequence of Interest for Pressurizer Power Operated Relief Valve Opens at Connecticut Yankee

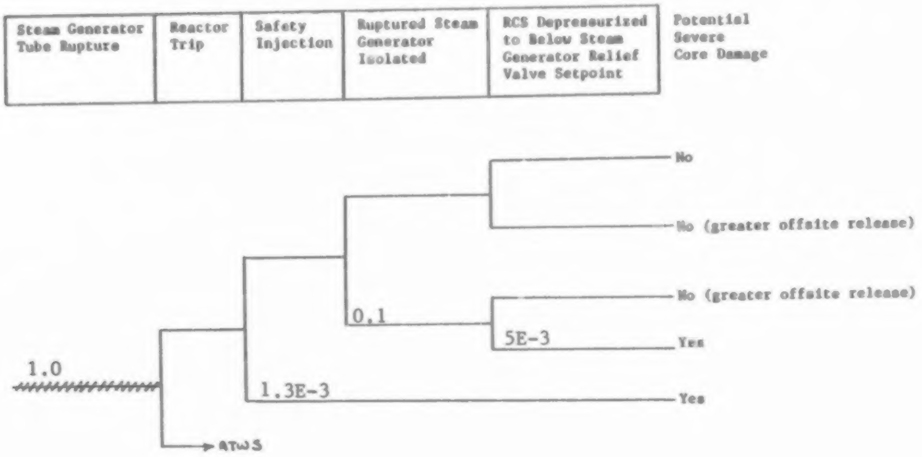
*Failure requires the operator to fail to close the PORV isolation valve.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
(D)
(CD)
0.1
2.9E-3
(CD)
1.3E-2
(CD)
1.2E-2
1.1E-2
(CD)
0.5
(CD)
1.2E-2
1.8E-2
(F*)
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 3.7E-3 x prob. of occurring at power (0.75) = 2.8E-3 (SC = 25)

NSIC 152187 — Sequence of Interest for Startup Transformer Fails and Diesel-Generator Fails to Start at St. Lucie 1

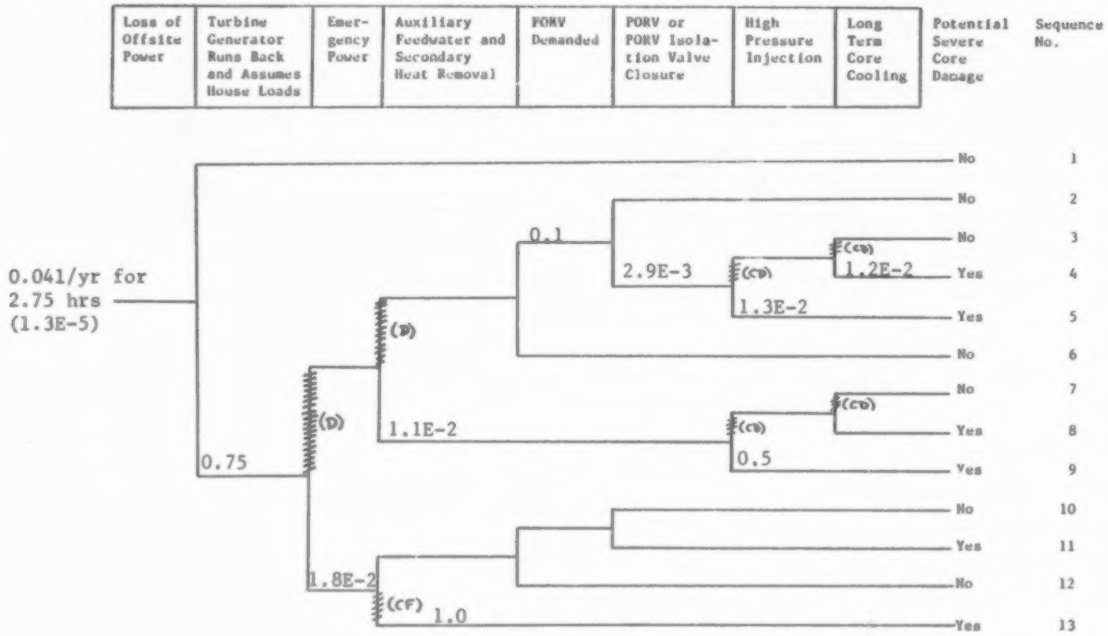
*Manual action may be successful in initiating the turbine-driven AFW pump.


Steam Generator Tube Rupture
Reactor Trip
Safety Injection
Ruptured Steam Generator Isolated
RCS Depressurized to Below Steam Generator Relief Valve Setpoint
Potential Severe Core Damage
1.0
0.1
5E-3
1.3E-3
ATWS
No
No (greater offsite release)
No (greater offsite release)
Yes
Yes

P = 1.8E-3 (SC = 27)

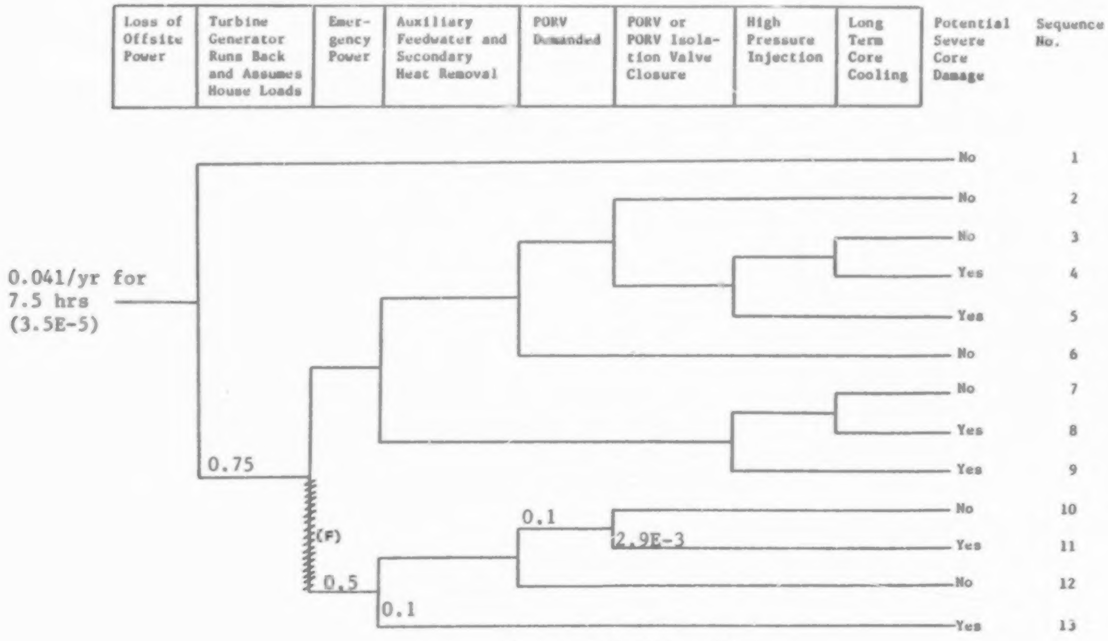
NSIC 152563 — Sequence of Interest for Tube Break Occurs at Prairie Island 1

BEST DOCUMENT AVAILABLE


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 2.75 hrs (1.3E-5)
0.75
(D)
(D)
0.1
2.9E-3
(CD)
(CD)
1.2E-2
1.3E-2
1.1E-2
(CD)
(CD)
0.5
1.8E-2
(CF)
1.0
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

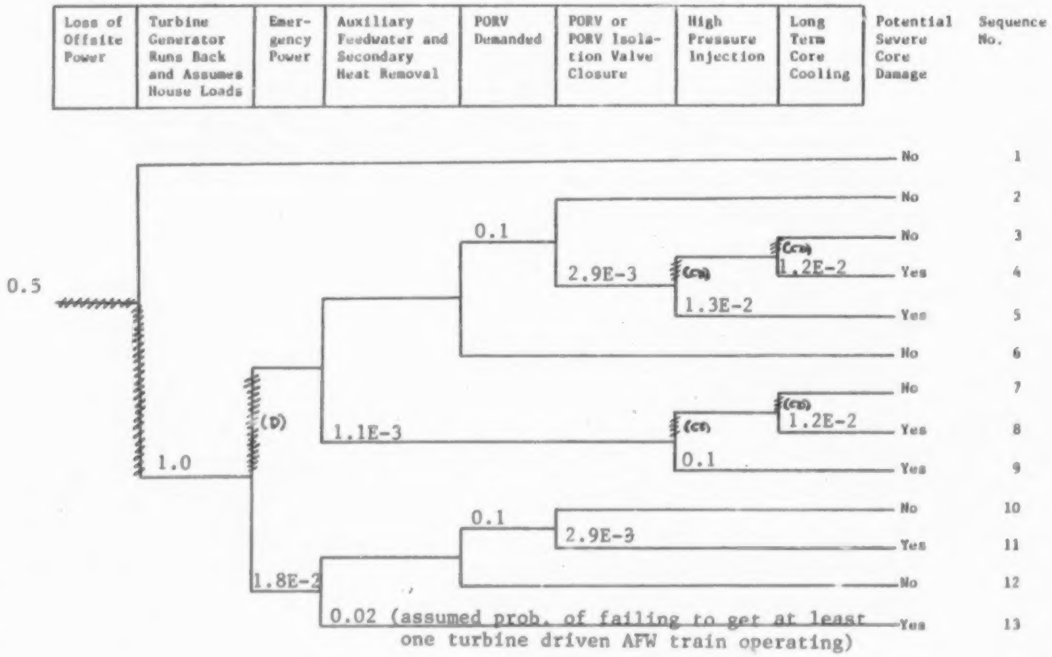
P = 2.3E-7 (SC = 66)

NSIC 152638 — Sequence of Interest for Two Auxiliary Feedwater Pumps Concurrently Unavailable at Cook 2


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 7.5 hrs (3.5E-5)
0.75
(F)
0.5
0.1
0.1
2.9E-3
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

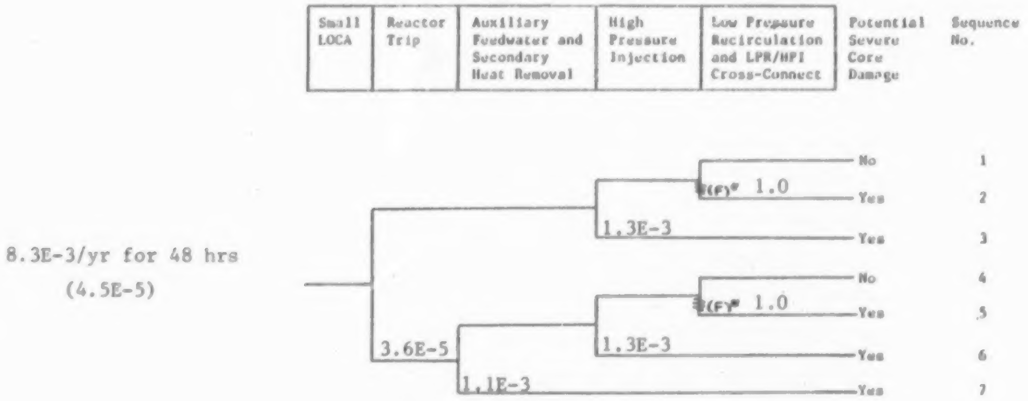
P = 1.3E-6 (SC = 59)

NSIC 152835 — Sequence of Interest for Engineered Safety Features Actuation System Failed at Calvert Cliffs 1


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.5
1.0
(D)
0.1
2.9E-3
(CN)
1.3E-2
(CN)
1.2E-2
1.1E-3
(CN)
0.1
(CN)
1.2E-2
0.1
2.9E-3
1.8E-2
0.02 (assumed prob. of failing to get at least one turbine driven AFW train operating)
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 2.4E-4 (SC = 36)

NSIC 152951 — Sequence of Interest for Offsite Power Lost at Davis-Besse 1

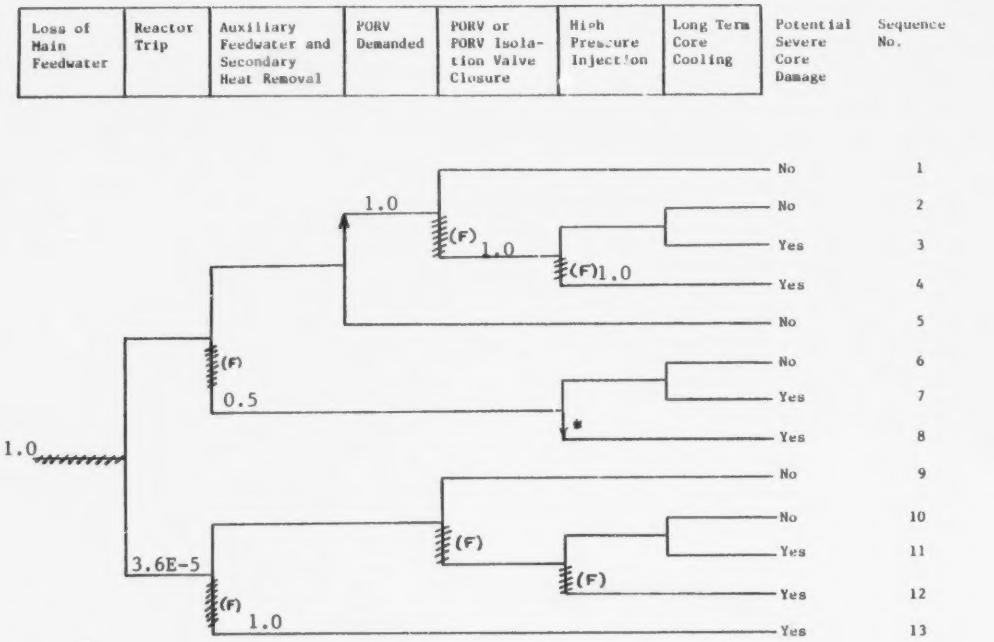

Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
8.3E-3/yr for 48 hrs
(4.5E-5)
(F)* 1.0
1.3E-3
(F)* 1.0
1.3E-3
3.6E-5
1.1E-3
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 4.5E-5 (SC = 43)

NSIC 153003 — Sequence of Interest for LPR Service Water Valves Left Closed Following Testing at Oconee 2

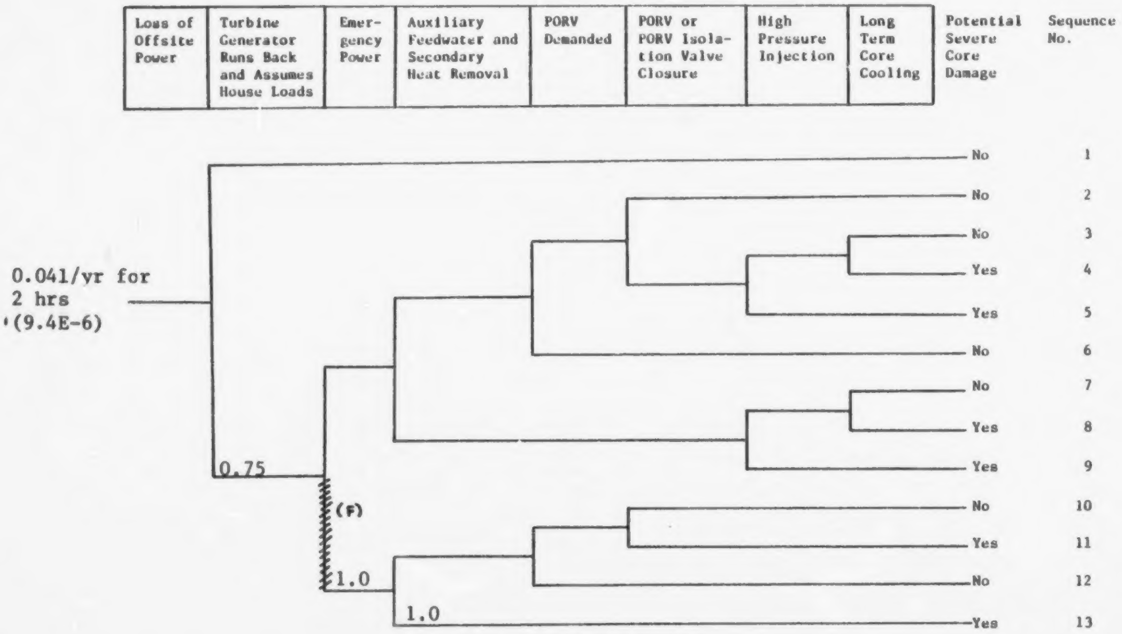
*Success requires operator detection and opening of closed valves prior to need for LPR.

[redacted]


Loss of Main Feedwater
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
1.0
1.0
(F)
1.0
(F) 1.0
(F)
0.5
*
3.6E-5
(F)
(F)
(F) 1.0
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

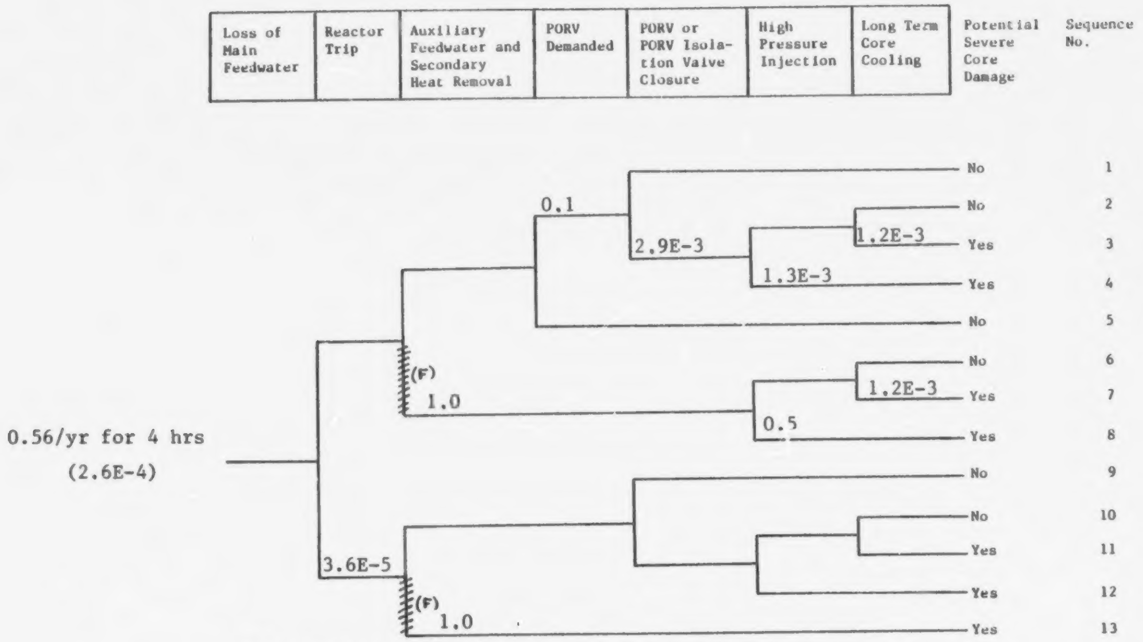
P = 1 (SC = 0)

NSIC 153164 — Sequence of Interest for Core Damage and Radioactivity Release Occurs at Three Mile Island 2
*Not included in mitigation procedures.


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 2 hrs (9.4E-6)
0.75
(F)
1.0
1.0
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

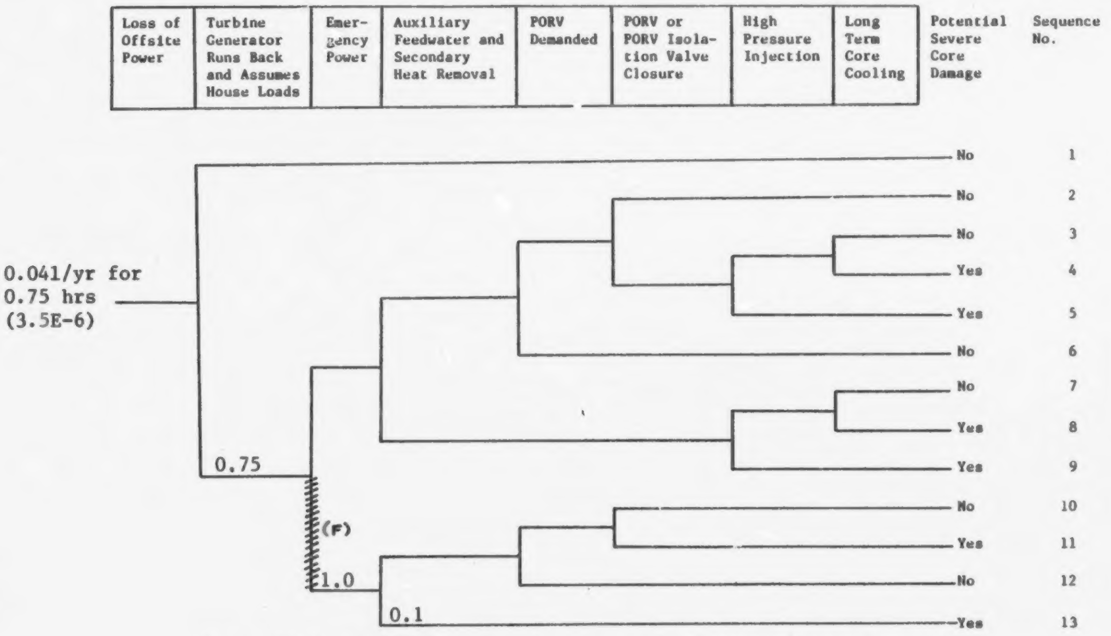
P = 7E-6 (SC = 52)

NSIC 153167 — Sequence of Interest for Gas Turbine Power Supplies Fail at Oconee


Loss of Main Feedwater
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.56/yr for 4 hrs
(2.6E-4)
0.1
2.9E-3
1.2E-3
1.3E-3
(F)
1.0
1.2E-3
0.5
3.6E-5
(F)
1.0
No 1
No 2
Yes 3
Yes 4
No 5
No 6
Yes 7
Yes 8
No 9
No 10
Yes 11
Yes 12
Yes 13

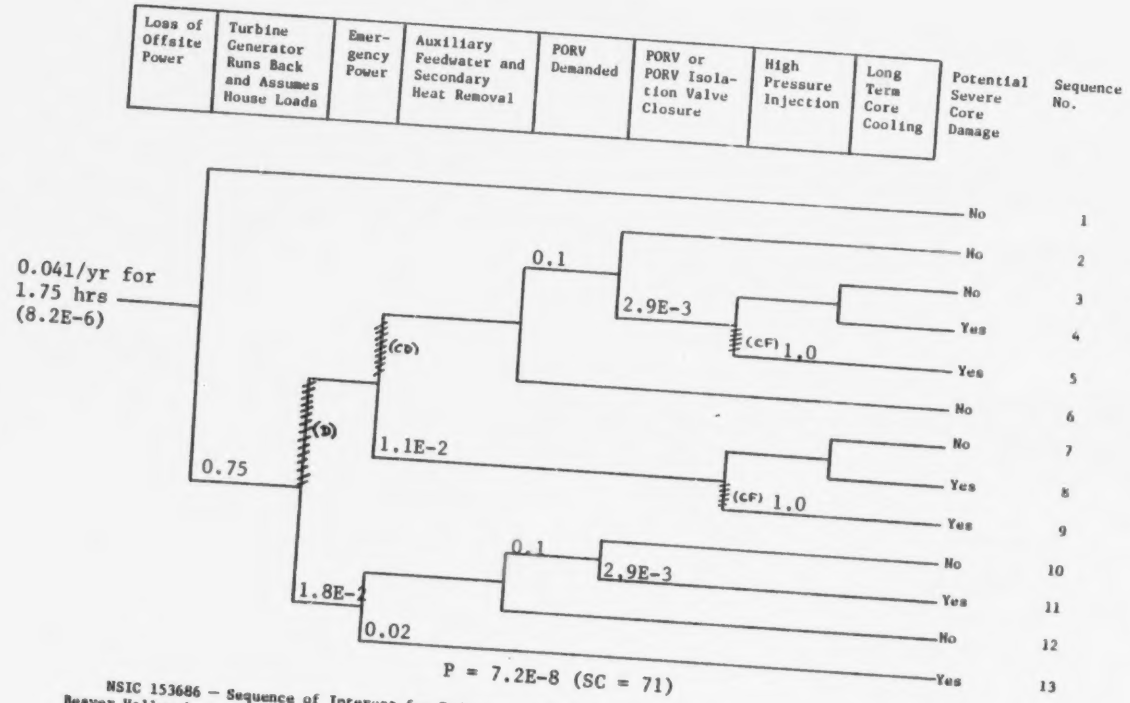
P = 1.3E-4 + addl. cont. (LOOP), 7E-6 = 1.4E-4 x prob. of occurring at power (0.75) = 1.1E-4 (SC = 40)

NSIC 153333 — Sequence of Interest for Flowpath from AFW Pump to Two Steam Generators Made Inoperable at Cook 1

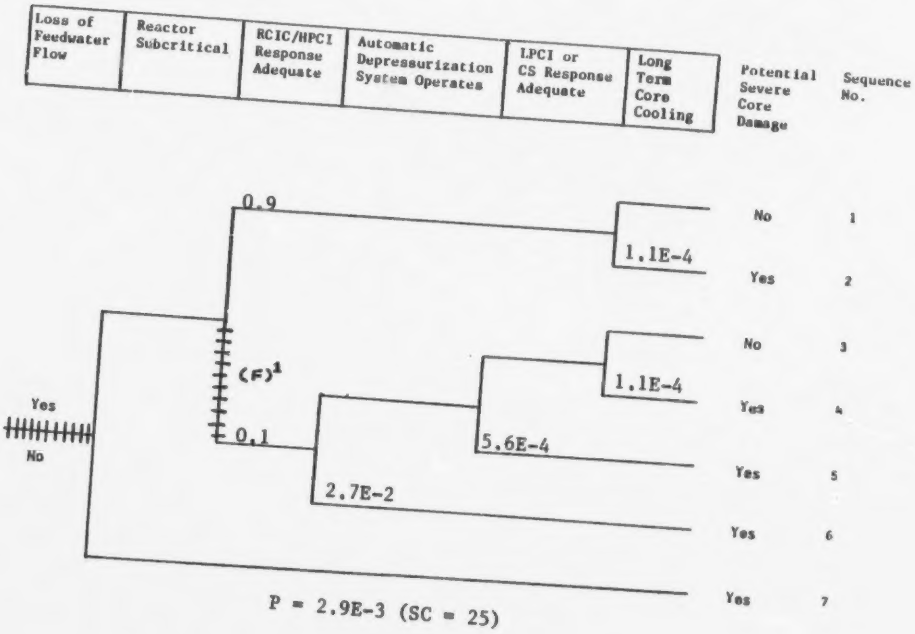

Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for
0.75 hrs
(3.5E-6)
0.75
(F)
1.0
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 2.6E-7 x prob. of occurring at power (0.75) = 2E-7 (SC = 67)

NSIC 153338 — Sequence of Interest for Maintenance Performed on Wrong Diesel Generator at Cook 2


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV Isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for 1.75 hrs (8.2E-6)
0.75
(D)
(CD)
0.1
2.9E-3
(CF) 1.0
1.1E-2
(CF) 1.0
1.8E-2
0.1
2.9E-3
0.02
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13
P = 7.2E-8 (SC = 71)

NSIC 153686 – Sequence of Interest for Redundant High Head Safety Injection Pumps Made Inoperable at Beaver Valley 1


Loss of Feedwater Flow
Reactor Subcritical
RCIC/HPCI Response Adequate
Automatic Depressurization System Operates
LPCI or CS Response Adequate
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
Yes
No
0.9
1.1E-4
(F)1
0.1
5.6E-4
1.1E-4
2.7E-2
No 1
Yes 2
No 3
Yes 4
Yes 5
Yes 6
Yes 7
P = 2.9E-3 (SC = 25)

NSIC 153810 – Sequence of Interest for RCIC Turbine Trip with HPCI Unavailable at Brunswick 1

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[1] Success requires the operator to reset and manually start RCIC.

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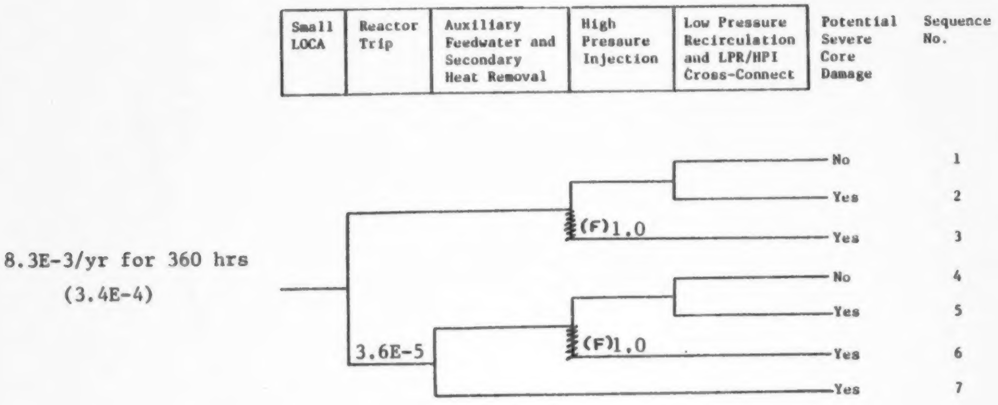
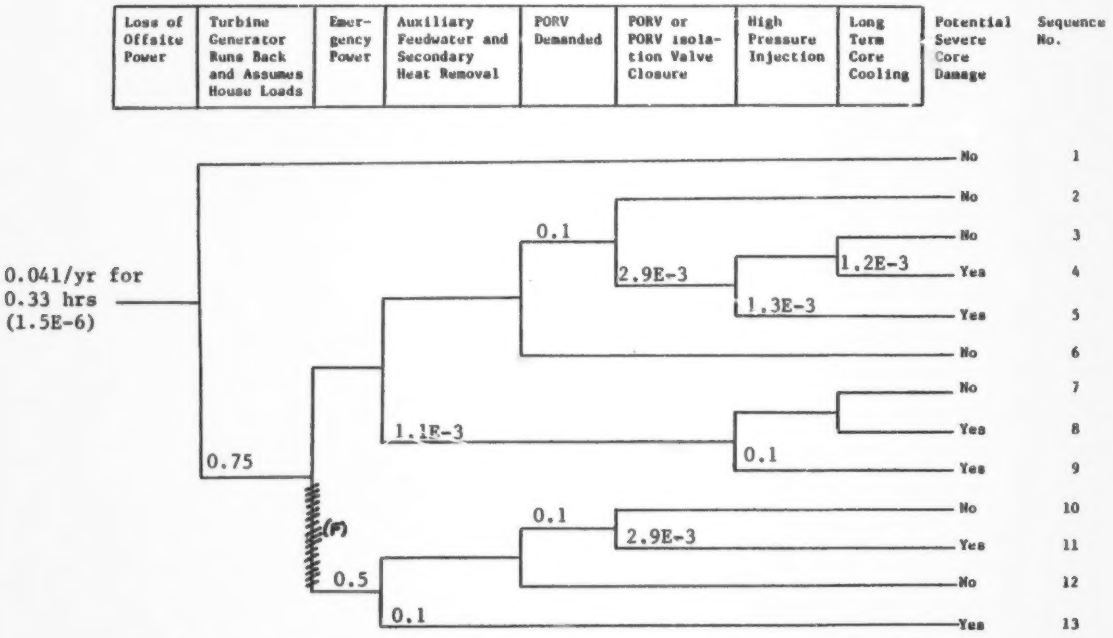

Small LOCA
Reactor Trip
Auxiliary Feedwater and Secondary Heat Removal
High Pressure Injection
Low Pressure Recirculation and LPR/HPI Cross-Connect
Potential Severe Core Damage
Sequence No.
8.3E-3/yr for 360 hrs
(3.4E-4)
(F)1.0
3.6E-5
(F)1.0
No 1
Yes 2
Yes 3
No 4
Yes 5
Yes 6
Yes 7

P = 3.4E-4 + addl. cont. (LOFW), 3.2E-5 = 3.7E-4 x prob. of occurring at power (0.75) = 2.8E-4 (SC = 35)

NSIC 154286 – Sequence of Interest for Safety Injection Pump Fails at Salem 1


Loss of Offsite Power
Turbine Generator Runs Back and Assumes House Loads
Emergency Power
Auxiliary Feedwater and Secondary Heat Removal
PORV Demanded
PORV or PORV isolation Valve Closure
High Pressure Injection
Long Term Core Cooling
Potential Severe Core Damage
Sequence No.
0.041/yr for
0.33 hrs
(1.5E-6)
0.1
2.9E-3
1.2E-3
1.3E-3
1.1E-3
0.1
0.75
(F)
0.1
2.9E-3
0.5
0.1
No 1
No 2
No 3
Yes 4
Yes 5
No 6
No 7
Yes 8
Yes 9
No 10
Yes 11
No 12
Yes 13

P = 5.6E-8 x prob. of occurring at power (0.75) = 4.2E-8 (SC = 73)

NSIC 154639 – Sequence of Interest for Both Diesel Generators Unavailable at Davis Besse 1

Appendix D

SUPPORT MATERIAL FOR TRENDS ANALYSIS - TIME ON TEST PLOTS

[redacted]

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D.8	Time on test plot for BWR failure of emergency power	D.11
D.9	Time on test plot for PWR failure of auxiliary feedwater	D.11
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Appendix D

SUPPORT MATERIAL FOR TRENDS ANALYSIS — TIME ON TEST PLOTS

The time on test plot concept was used to determine instantaneous failure rates for the following initiating events and function failures (Fig. D.1 offers a test plot for example failures):

- loss of offsite power (Figs. D.2—D.4),
- small loss-of-coolant accident (Figs. D.5 and D.6),
- failure of emergency power (Figs. D.7 and D.8),
- failure of PWR auxiliary feedwater and secondary heat removal (Fig. D.9),
- failure of PWR high-pressure injection (Fig. D.10),
- failure of PWR long-term cooling (sump recirculation) (Fig. D.11),
- failure of PWR steam generator isolation (Fig. D.12),
- failure of PWR high-pressure injection following a steam line break (Fig. D.13),
- failure of BWR high-pressure coolant injection and reactor core isolation cooling (Fig. D.14),
- failure of automatic depressurization (Fig. D.15),
- failure of BWR reactor vessel isolation (Fig. D.16).

A total time on test plot* is a graphical method of determining an instantaneous failure rate distribution for a particular set of failure data. The method utilizes the fact that if an underlying instantaneous failure rate is constant, the observed percentage of failures will increase at approximately the same rate as the percent of total operating time increases. Thus, a plot of these percentages should produce an approximately straight line at a 45° angle. If the fractional failure rate is consistently less than the fractional total test time, the plot will lie below the 45° line, indicating a decreasing instantaneous failure rate; inversely, a fractional failure rate consistently greater than the fractional total test time will result in a plot that lies above the 45° line, indicating an increasing instantaneous failure rate.

As an example of the use of total time on test plots in determining instantaneous failure rate trends, consider a population of three repairable items that are observed up to the time the fifth failure occurs. These failures can be represented on individual time lines as follows:

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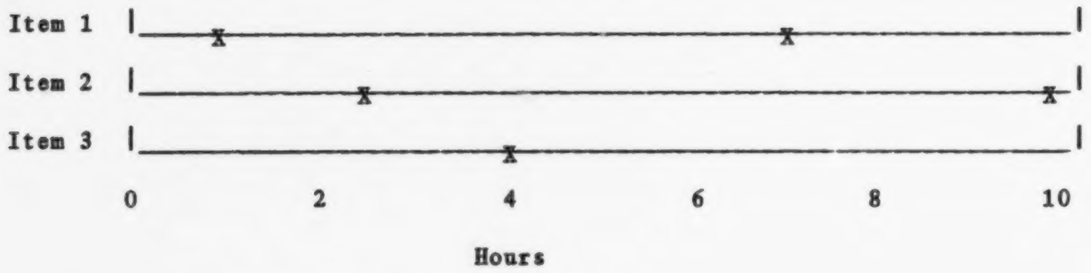
*R. E. Barlow and R. Campo, "Total Time on Test Processes and Applications to Failure Data Analysis," in *Reliability and Fault Tree Analysis*, pp. 451—81, Society for Industrial and Applied Mathematics, Philadelphia, 1975.



If these failures are then listed sequentially, starting with the first, the information in Table D.1 can be developed.

Table D.1. Example time on test plot calculations

Failure No.	Failure time (h)	Fraction of total failures	Total observation time to failure (h)	Fraction of total observation time
1	1	0.2	3	3/30 = 0.1
2	2.5	0.4	7.5	7.5/30 = 0.25
3	4	0.6	12	12/30 = 0.4
4	7	0.8	21	21/30 = 0.7
5	10	1.0	30	30/30 = 1.0

Plotting the fraction of total failures that have occurred (designated t on the plots herein) on the x-axis and the corresponding fraction of total observation time [designated $H_n^{-1}(t)/H_n^{-1}(1)$] on the y-axis, the plot shown in Fig. D.1 is obtained. Because the plot lies below the 45° line, a decreasing instantaneous failure rate is indicated.

Four cautions must be observed when this method is applied to the failure information included in the precursors.

1. All nuclear plants have not been critical for the full 11-year period. As discussed in Barlow and Campo (previously referenced), total time on test plots for this situation will still indicate trends in instantaneous failure rates but cannot be used for specific instantaneous failure rate model prediction.

2. Because the population of reactors is mixed, an observed instantaneous failure rate trend may be the result of combinations of instantaneous failure rate functions at each plant which are considerably different than that indicated for the total population. For example, a mixed

population of constant, but different, failure rates may exhibit a decreasing failure rate.[*]

3. The total time on test plots indicate instantaneous failure rate trends up to the time of the last observed failure. For many of the failures of interest in this study, the last observed failure (based on plant age) occurred at a rather early plant age. To include all the observed operating time in the plots, one additional failure was assumed to have occurred on the last day of observation for the oldest plant.

4. Certain initiating events and function failures included only a small number of failures. For consistency, failure rate trends were determined for these items; however, the confidence in the indicated results is low.

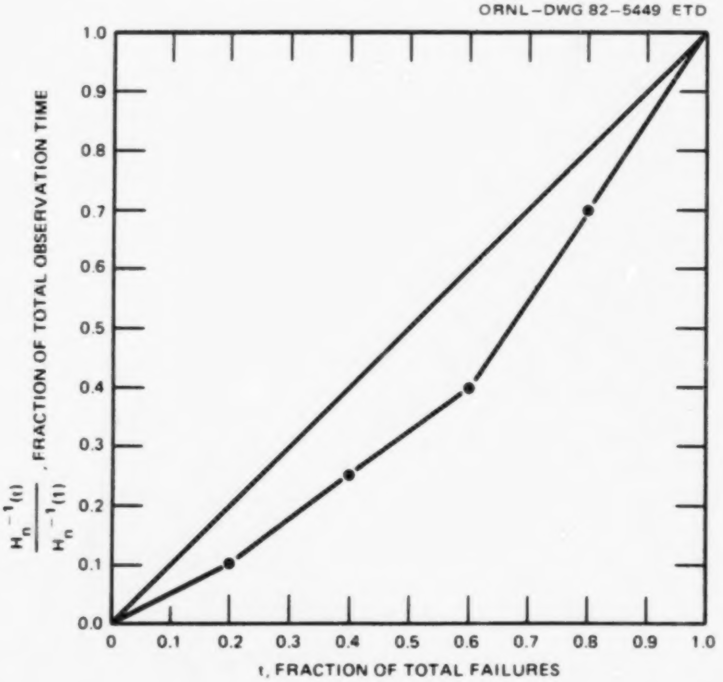


Fig. D.1. Time on test plot for example failures.

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[*] L. J. Bain, *Statistical Analysis of Reliability and Life-Testing Models*, pp. 117–19, Marcel Dekkar, New York, 1978.

[redacted]

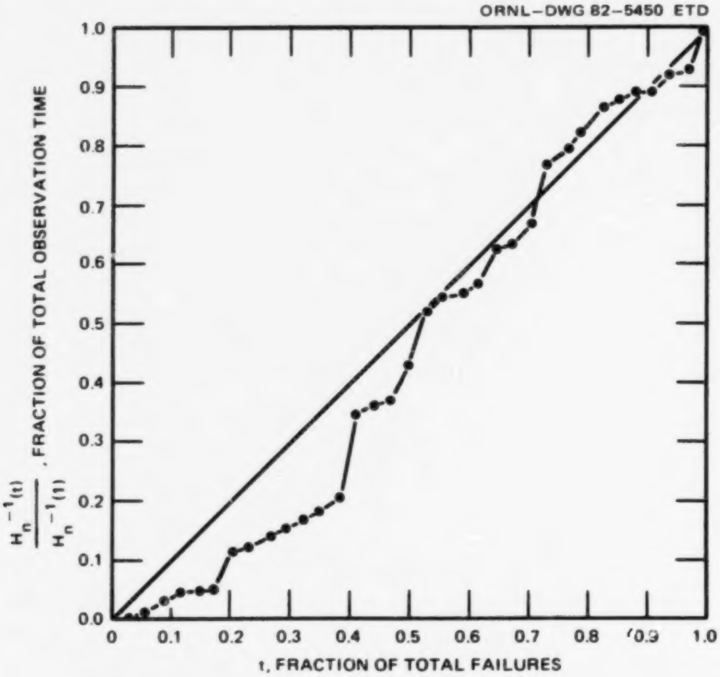

Fig. D.2. Time on test plot for PWR and BWR loss of offsite power.

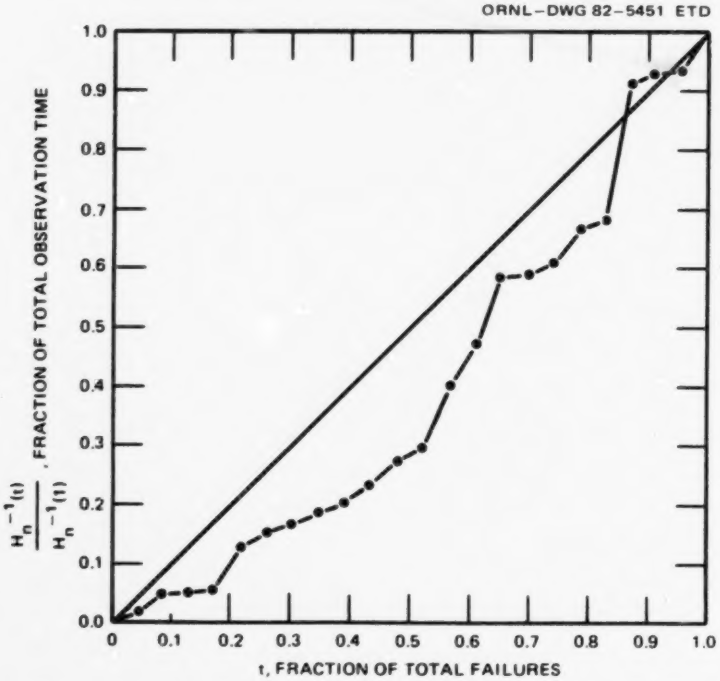

Fig. D.3. Time on test plot for PWR loss of offsite power.

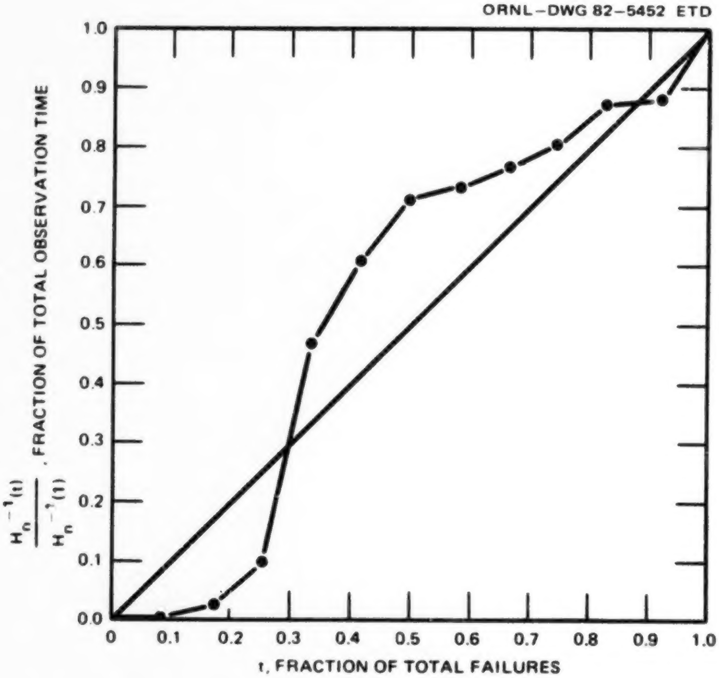

Fig. D.4. Time on test plot for BWR loss of offsite power.

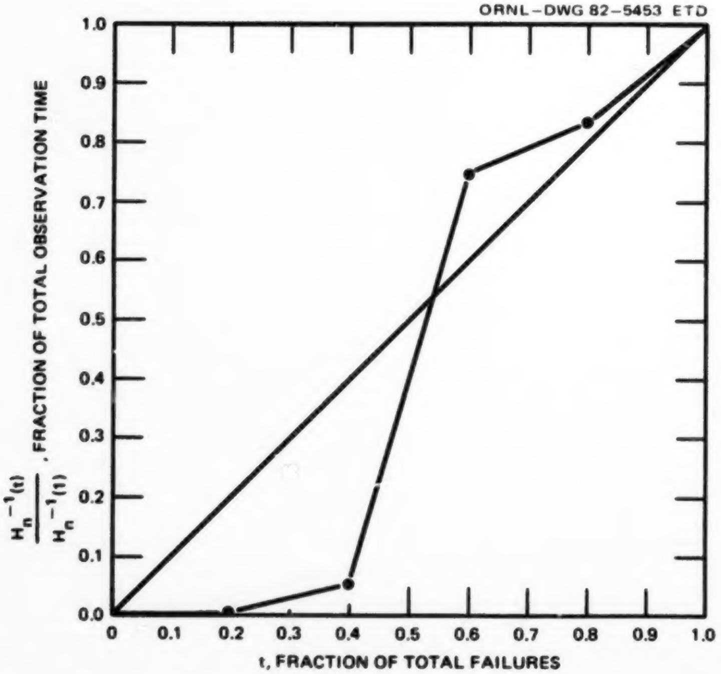

Fig. D.5. Time on test plot for PWR small LOCA.

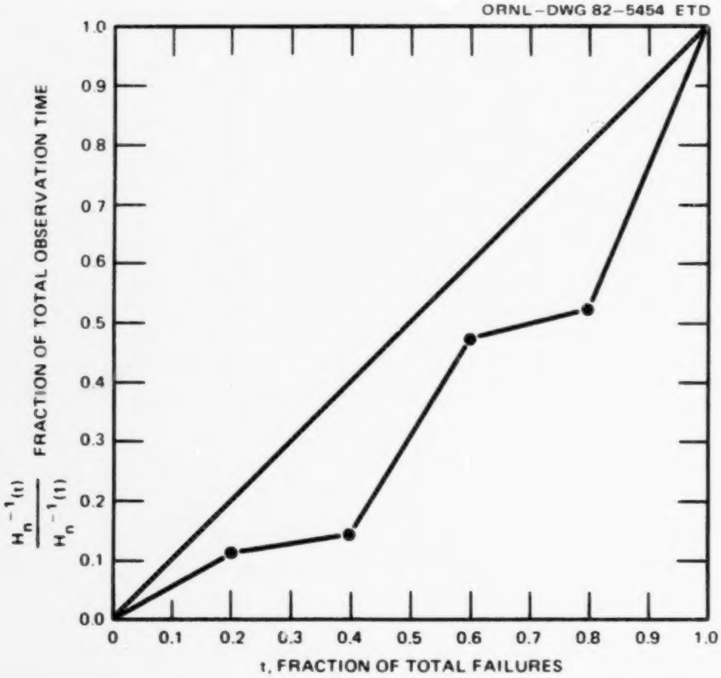

Fig. D.6. Time on test plot for BWR small LOCA.

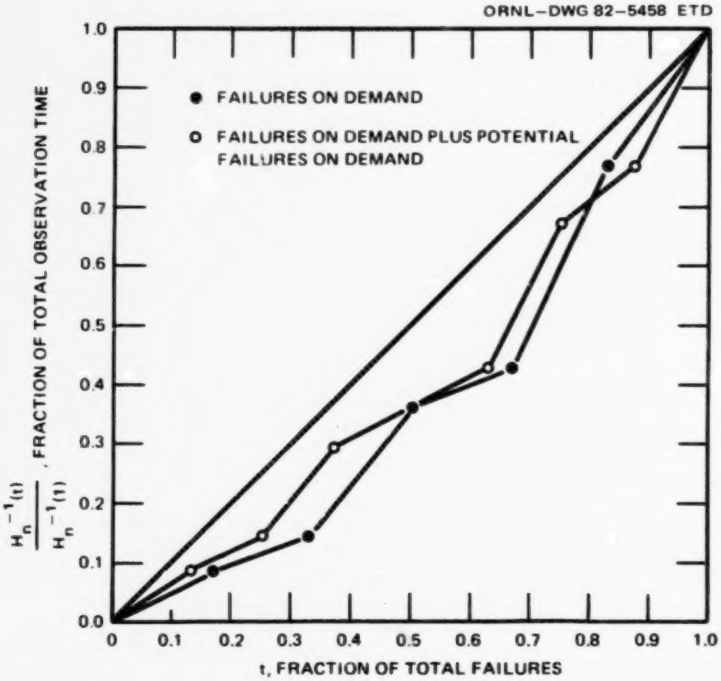

Fig. D.7. Time on test plot for PWR failure of emergency power.

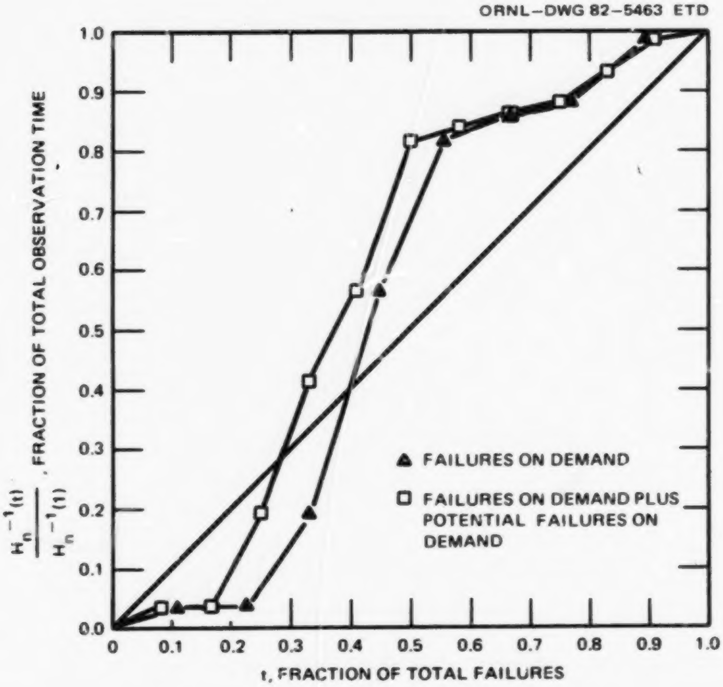

Fig. D.8. Time on test plot for BWR failure of emergency power.

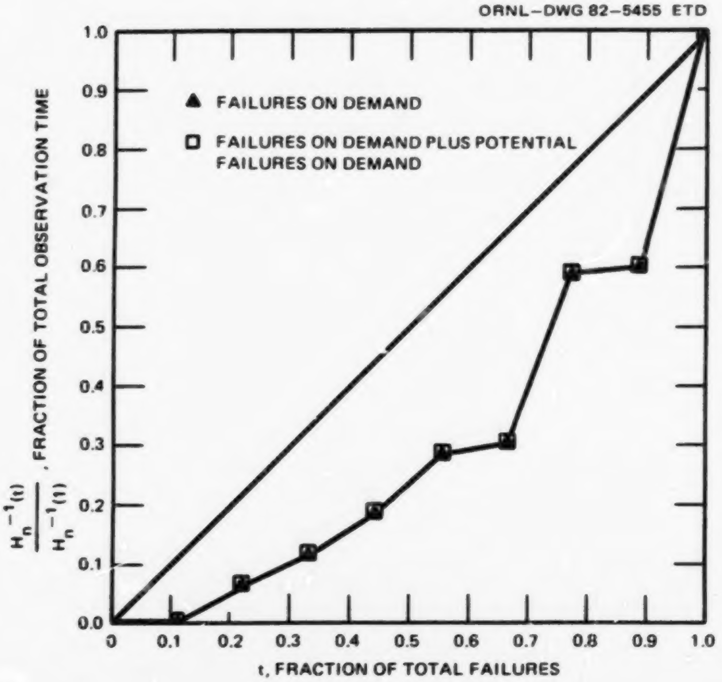

Fig. D.9. Time on test plot for PWR failure of auxiliary feedwater.

[redacted]

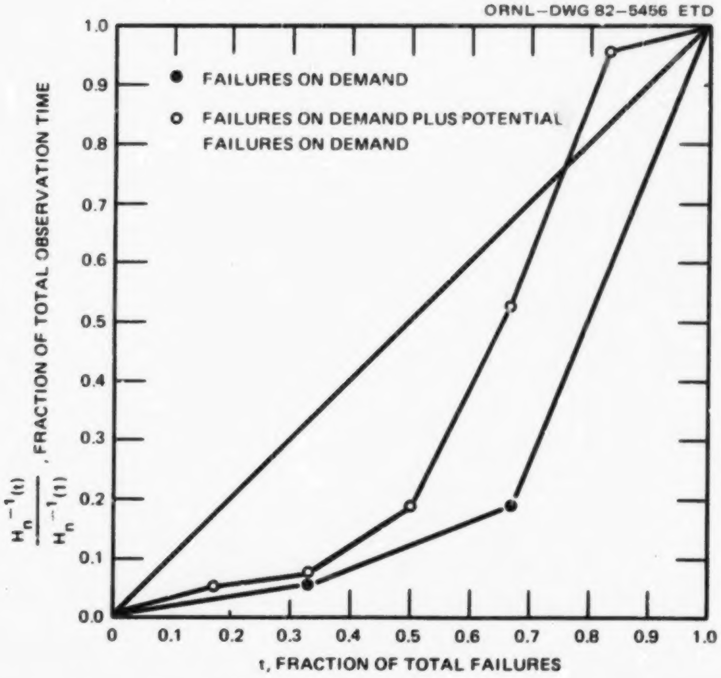

Fig. D.10. Time on test plot for PWR failure of high-pressure injection.

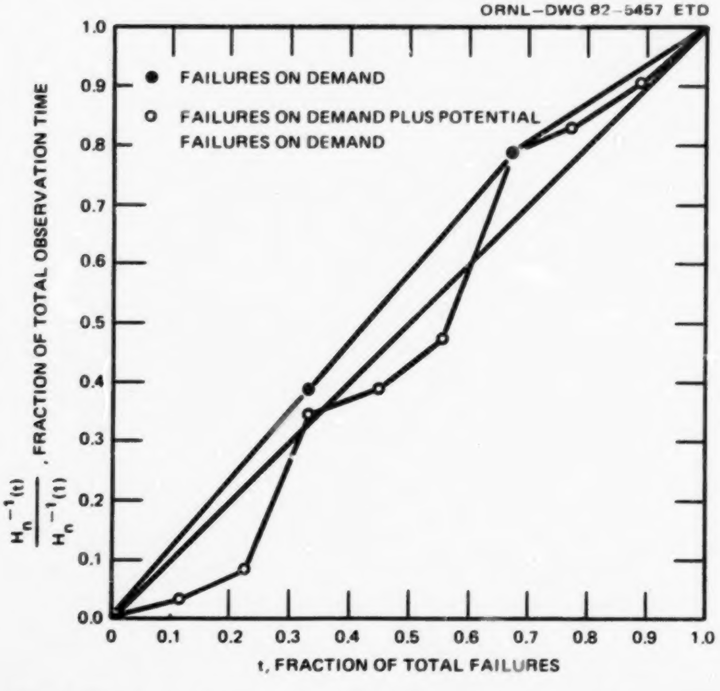

Fig. D.11. Time on test plot for PWR failure of long-term cooling.

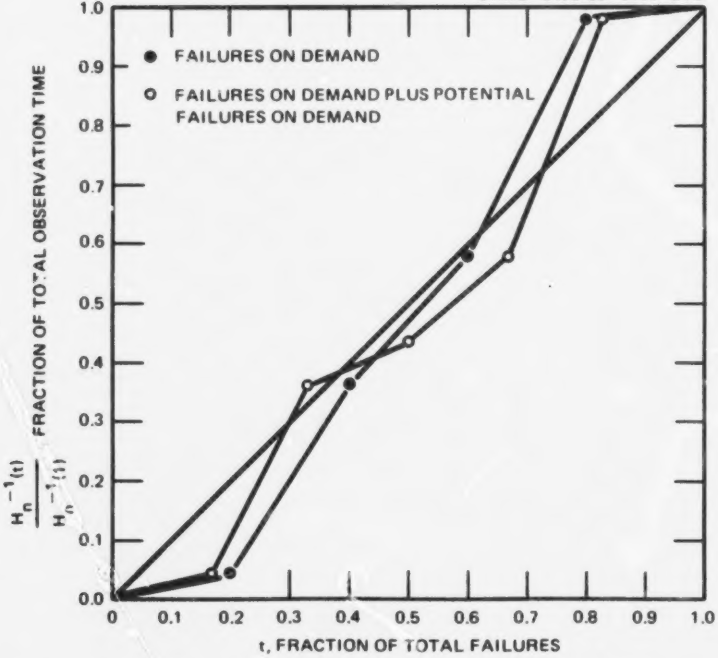

Fig. D.12. Time on test plot for PWR failure of steam generator isolation.

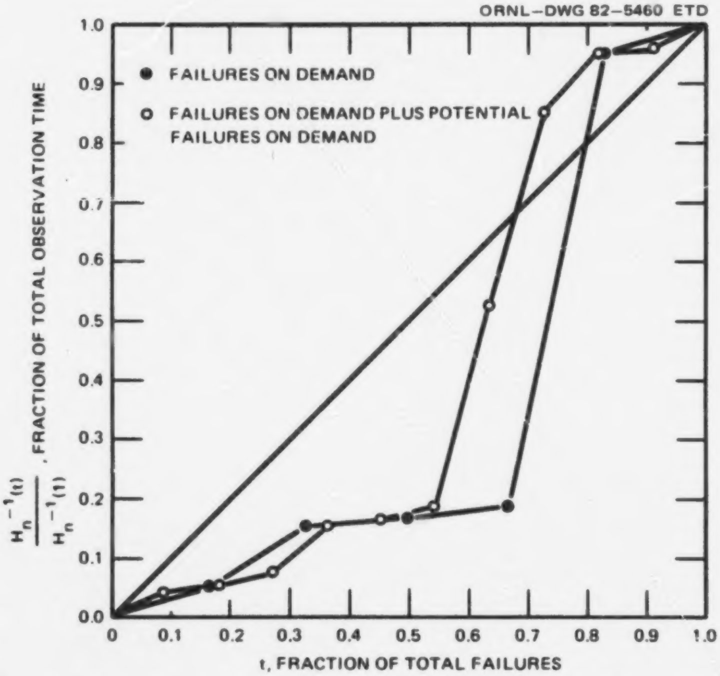

Fig. D.13. Time on test plot for PWR failure of high-pressure injection for steam line break.

[redacted]

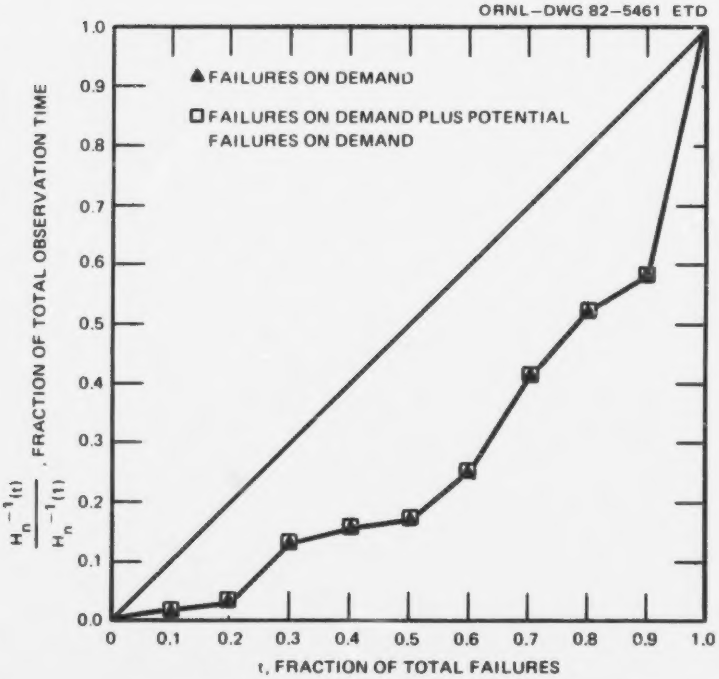

Fig. D.14. Time on test plot for BWR failure of high-pressure coolant injection/reactor core isolation cooling.

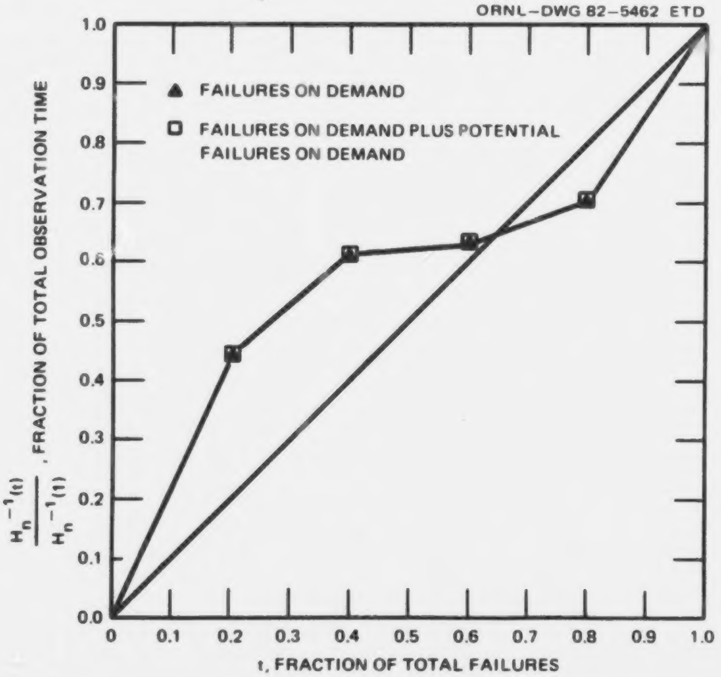

Fig. D.15. Time on test plot for BWR failure of automatic depressurization.

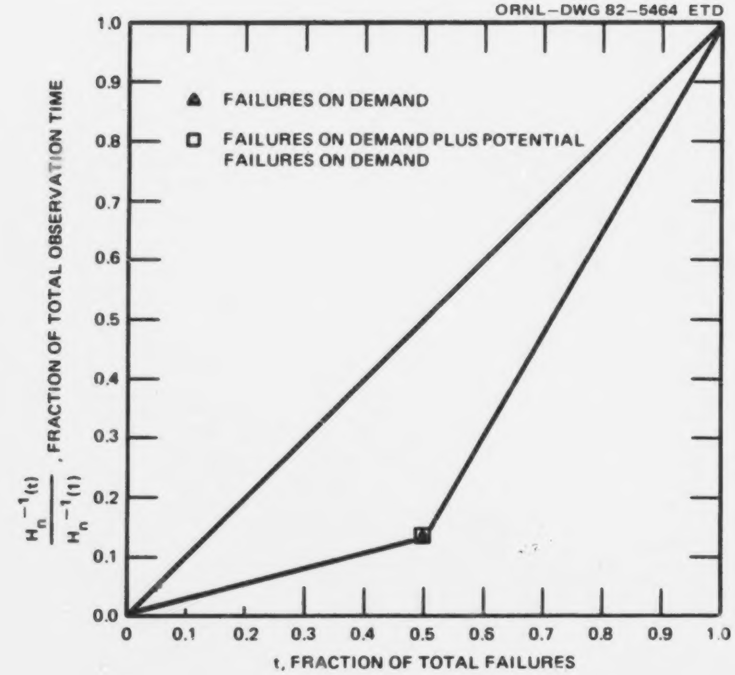

Fig. D.16. Time on test plot for BWR failure of reactor vessel isolation.

Appendix E

ADDITIONAL SUPPORT MATERIAL FOR TRENDS ANALYSIS

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Appendix E

ADDITIONAL SUPPORT MATERIAL FOR TRENDS ANALYSIS

This appendix contains additional supporting material for the trends analyses discussed in Chap. 5. Included are time lines for initiating events and function failures (Figs. E.1–E.14), degraded-function events that occurred within 1 month of reference plant and date combinations (Table E.1), and degraded-function events that occurred within 1 month of significant precursors (Table E.2).

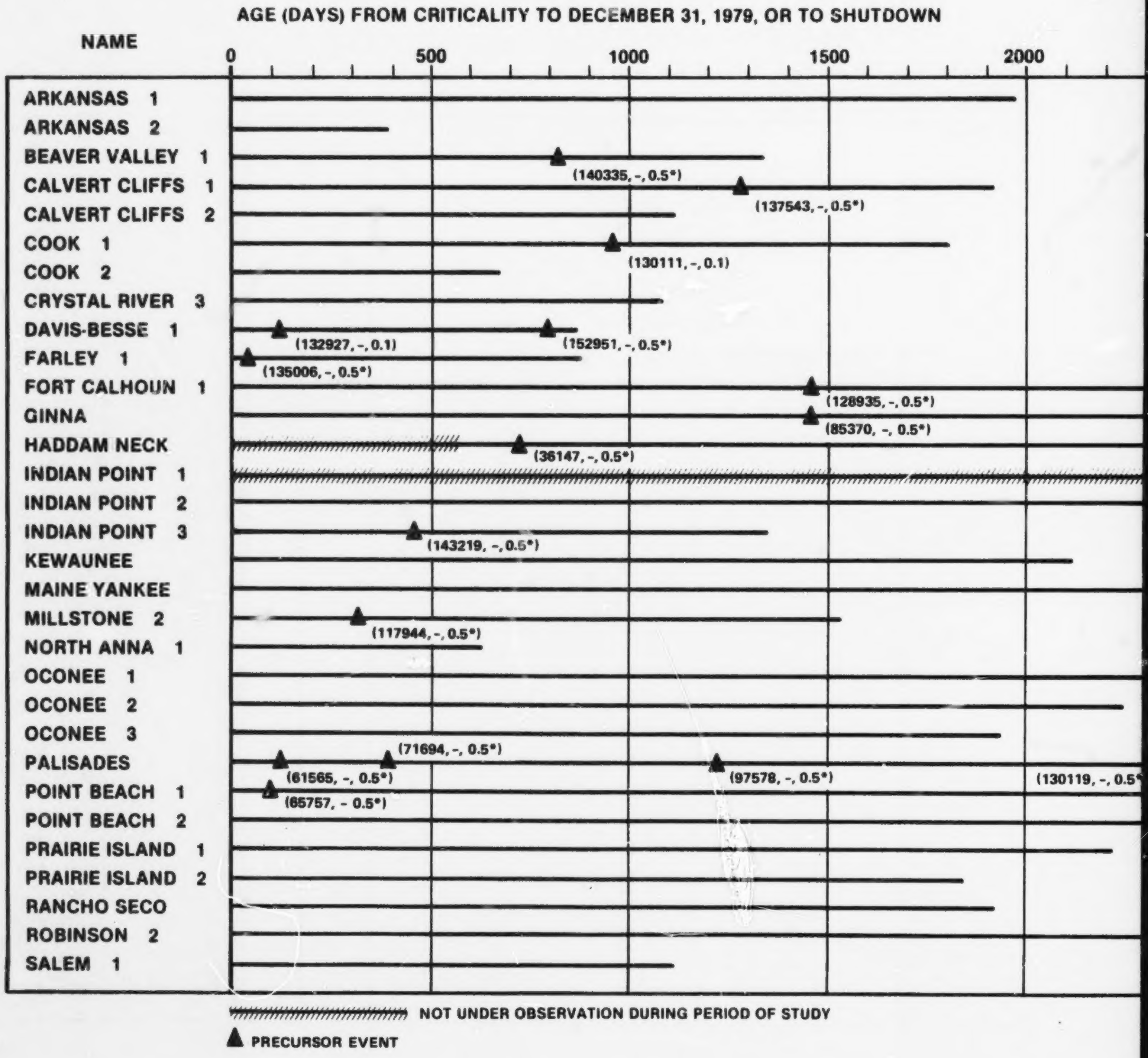

Fig. E.1. Time line for PWR loss of offsi

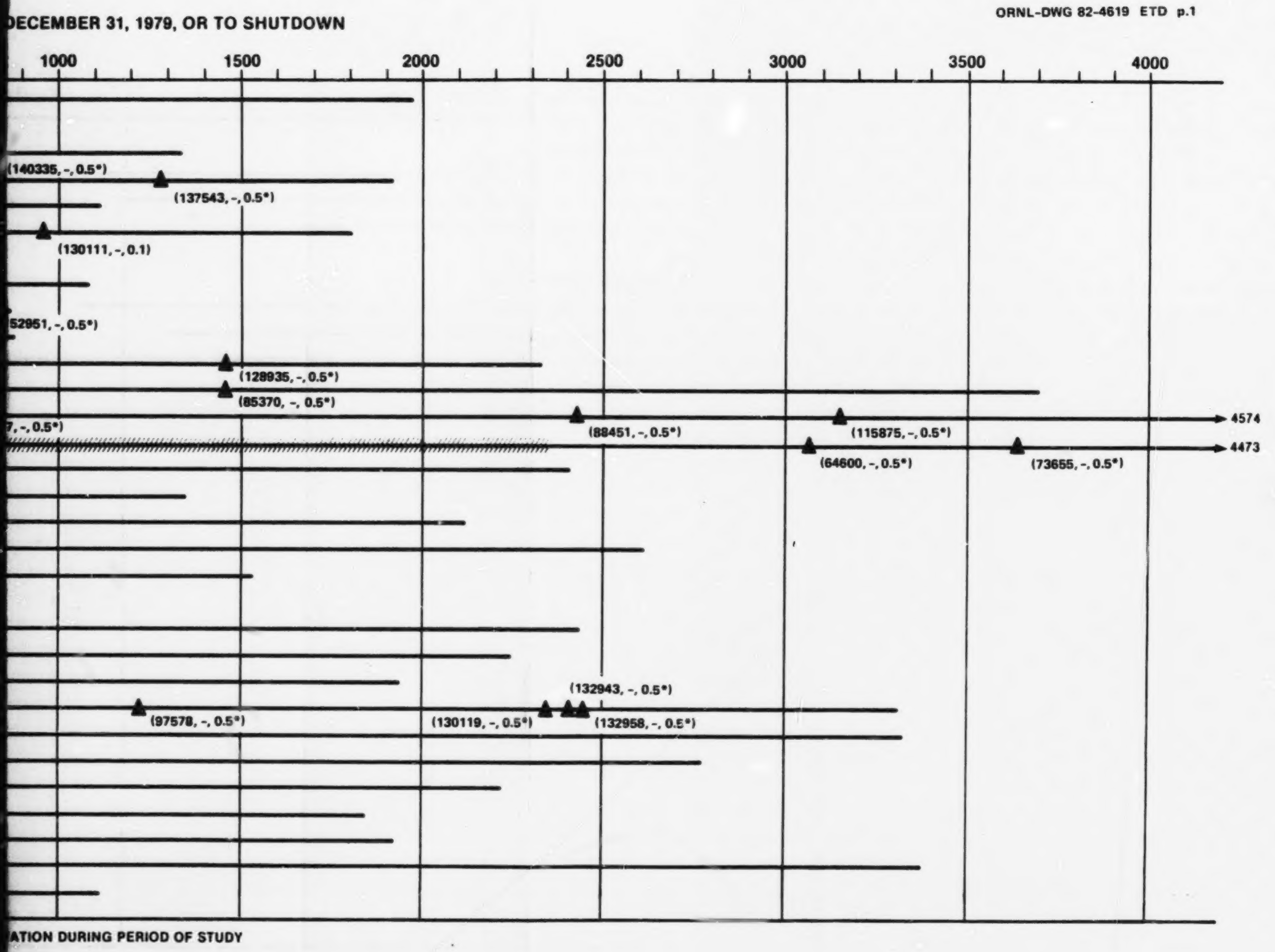

Fig. E.1. Time line for PWR loss of offsite power.

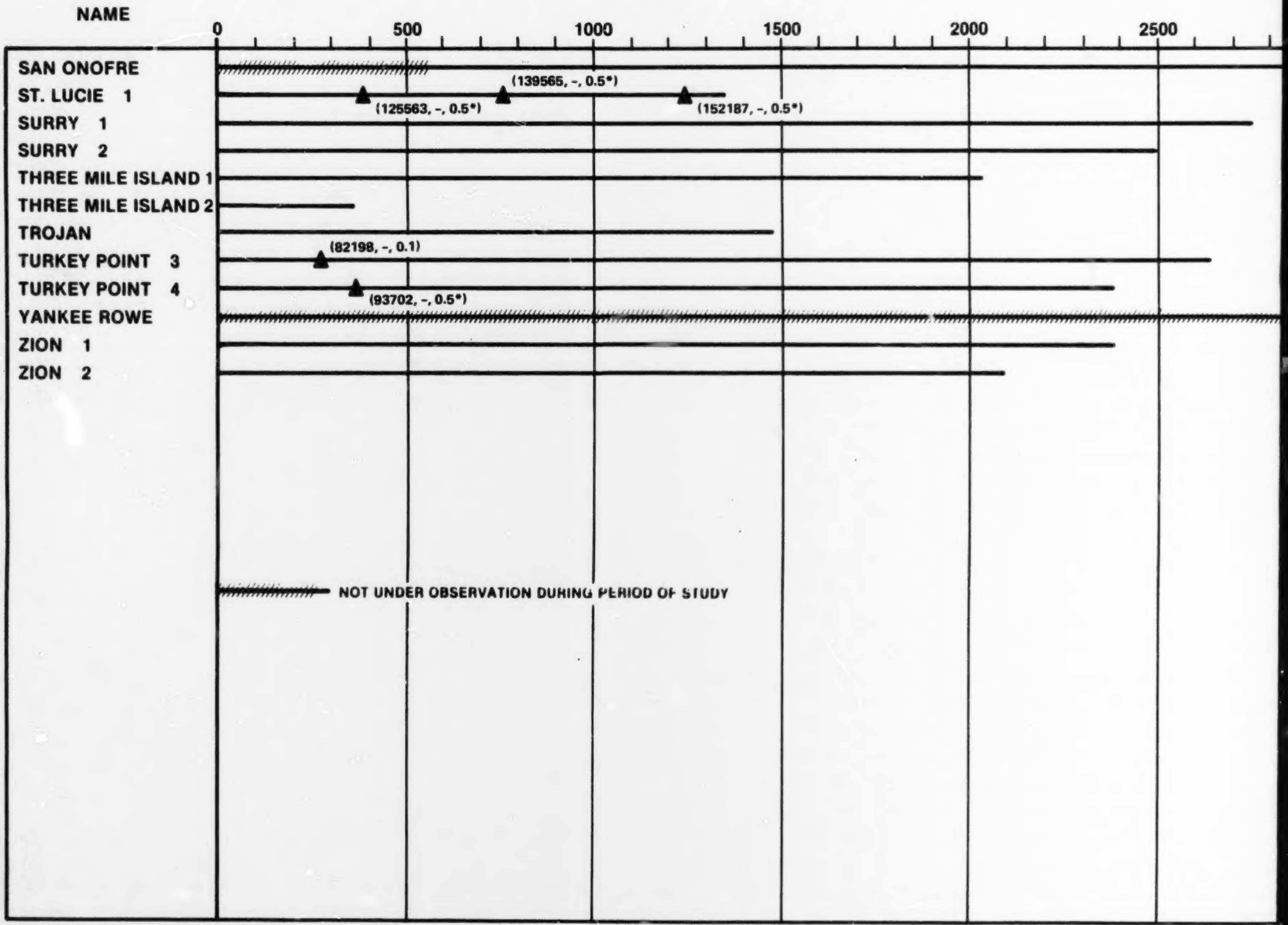

Fig. E.1 (continued)

ORNL-DWG 82-4619 ETD p.2

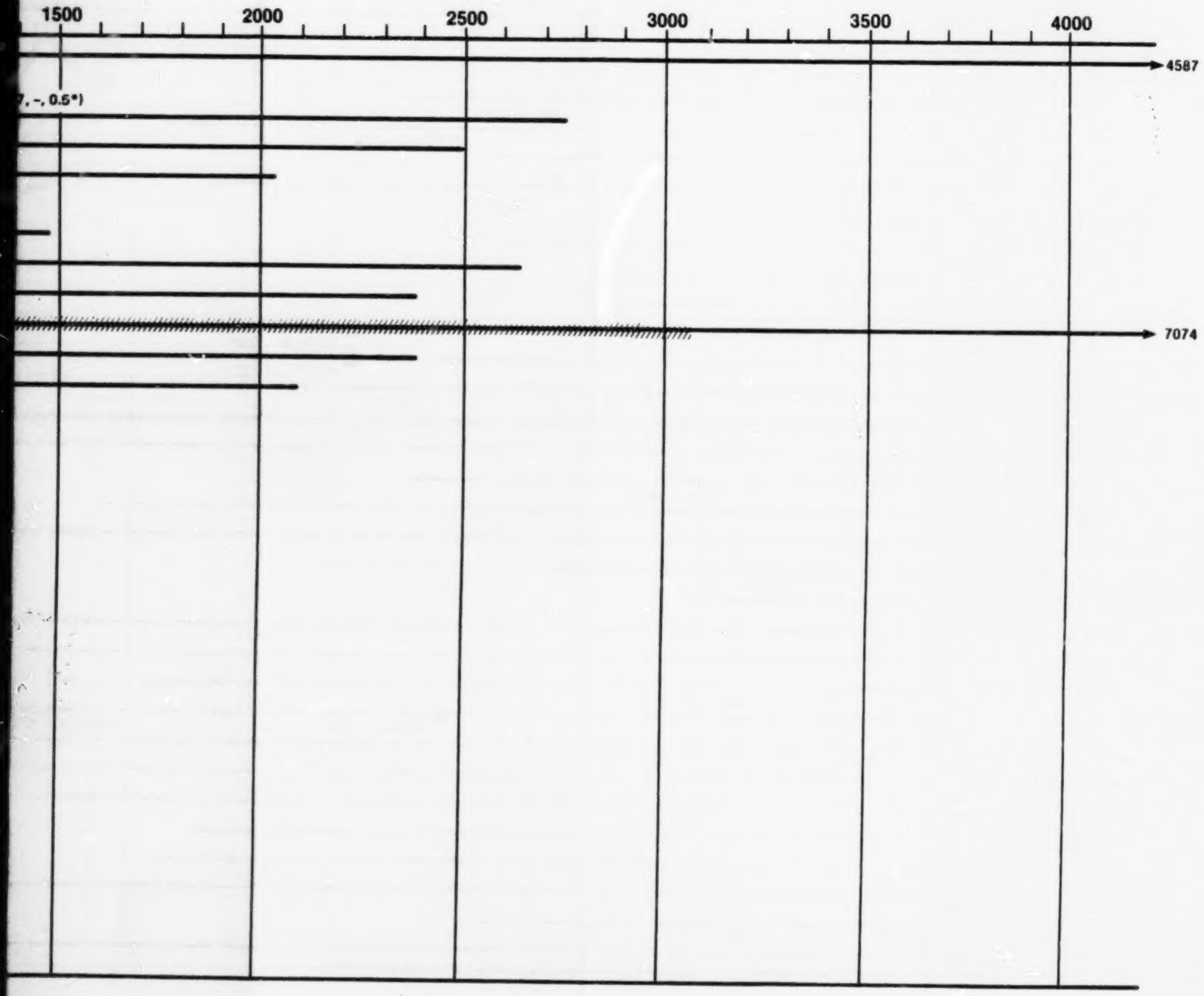

Fig. E.1 (continued)

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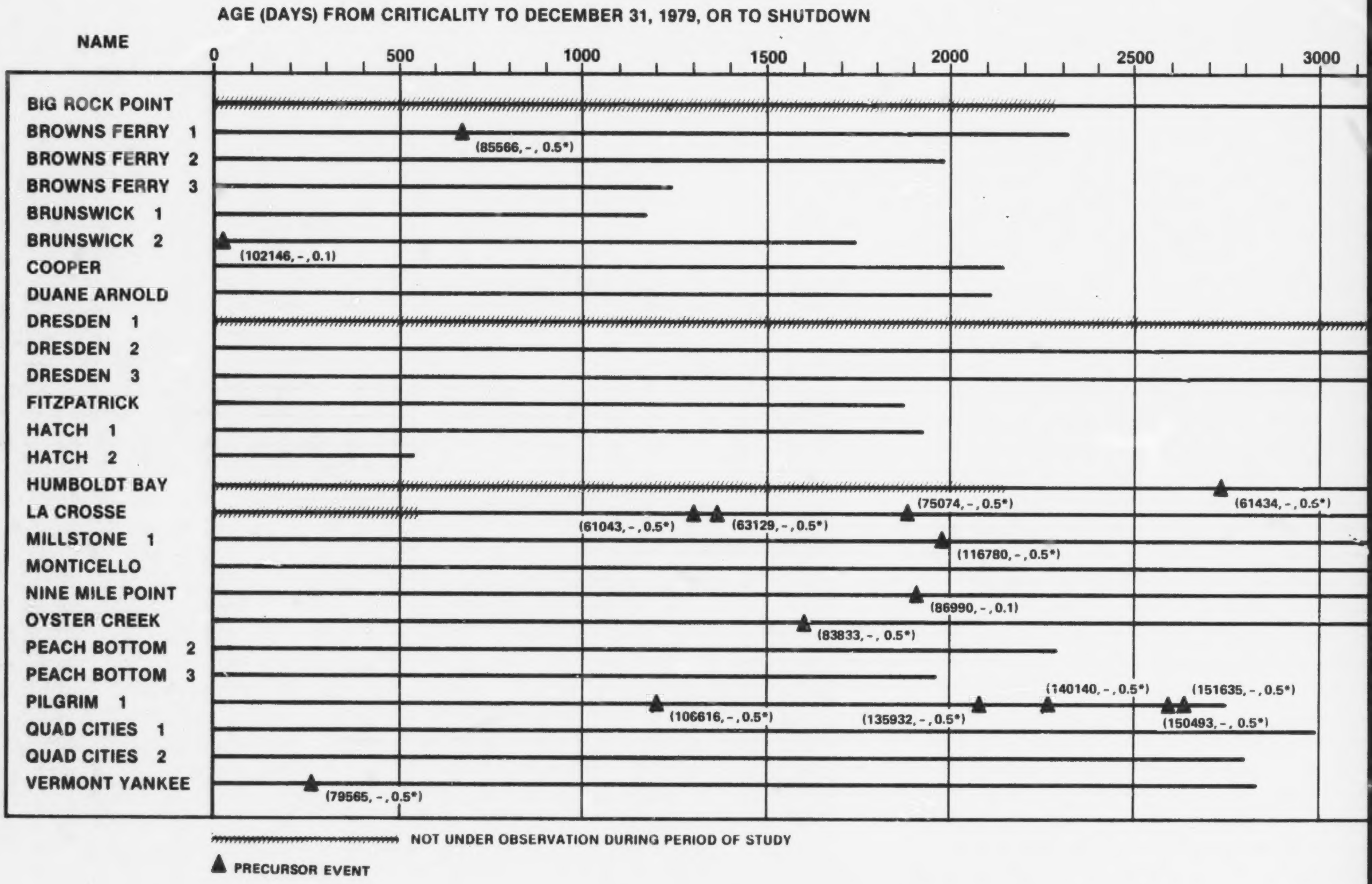
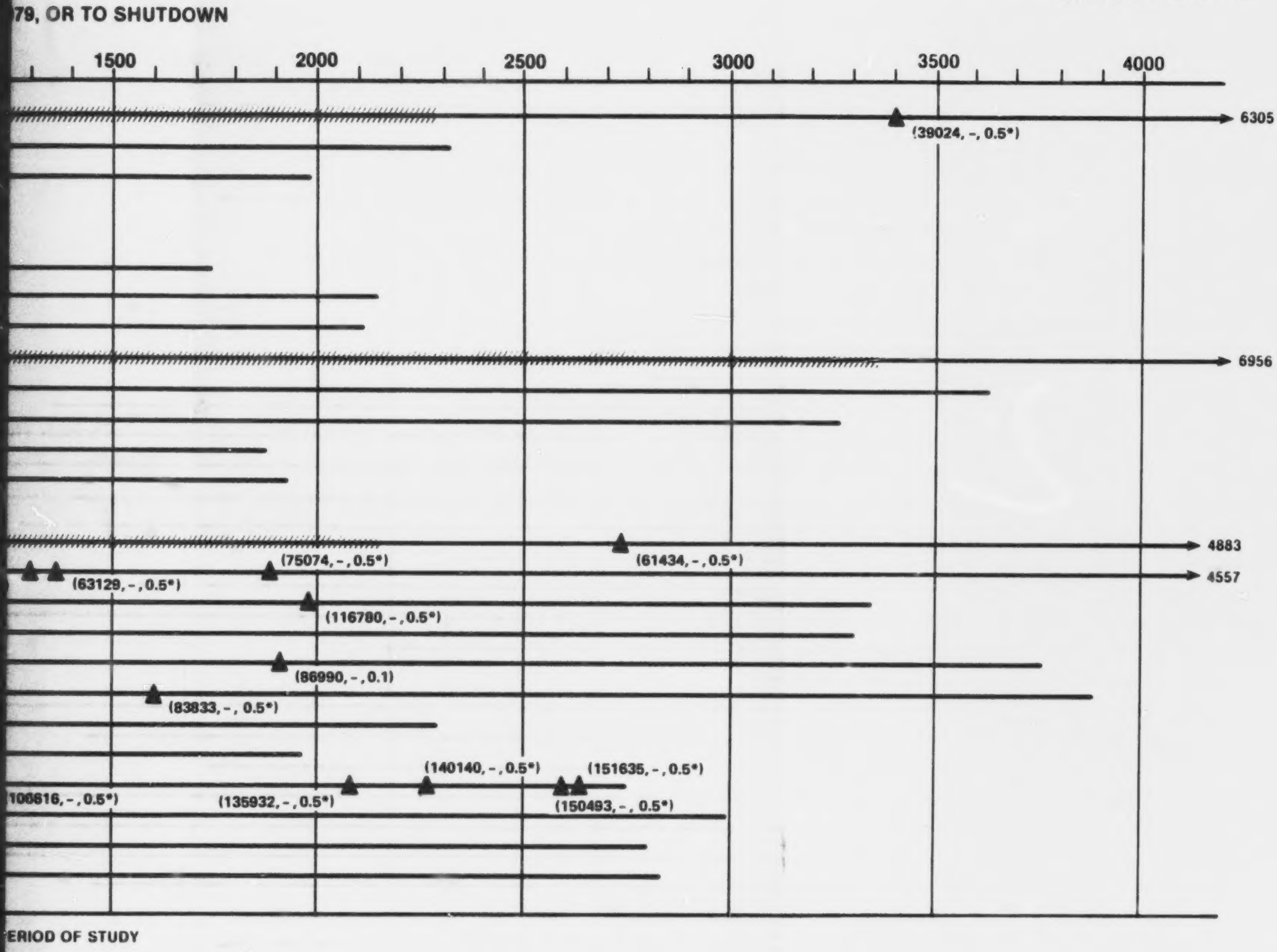


Fig. E.2. Time line for BWR loss of offsite power.

ORNL-DWG 82-4620 ETD



E.2. Time line for BWR loss of offsite power.

.224 A

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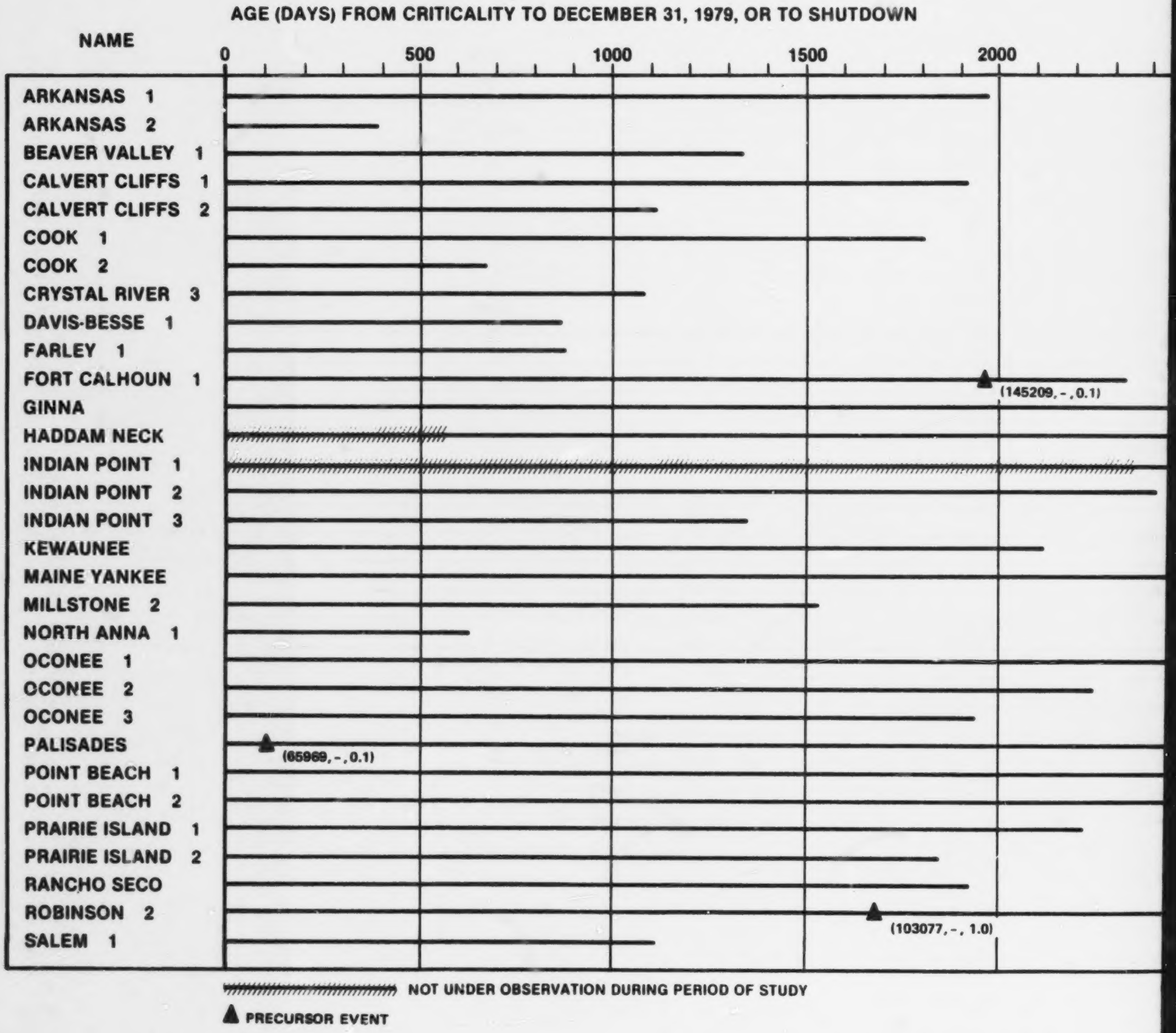

Fig. E.3. Time line for PWR small loss-of-c

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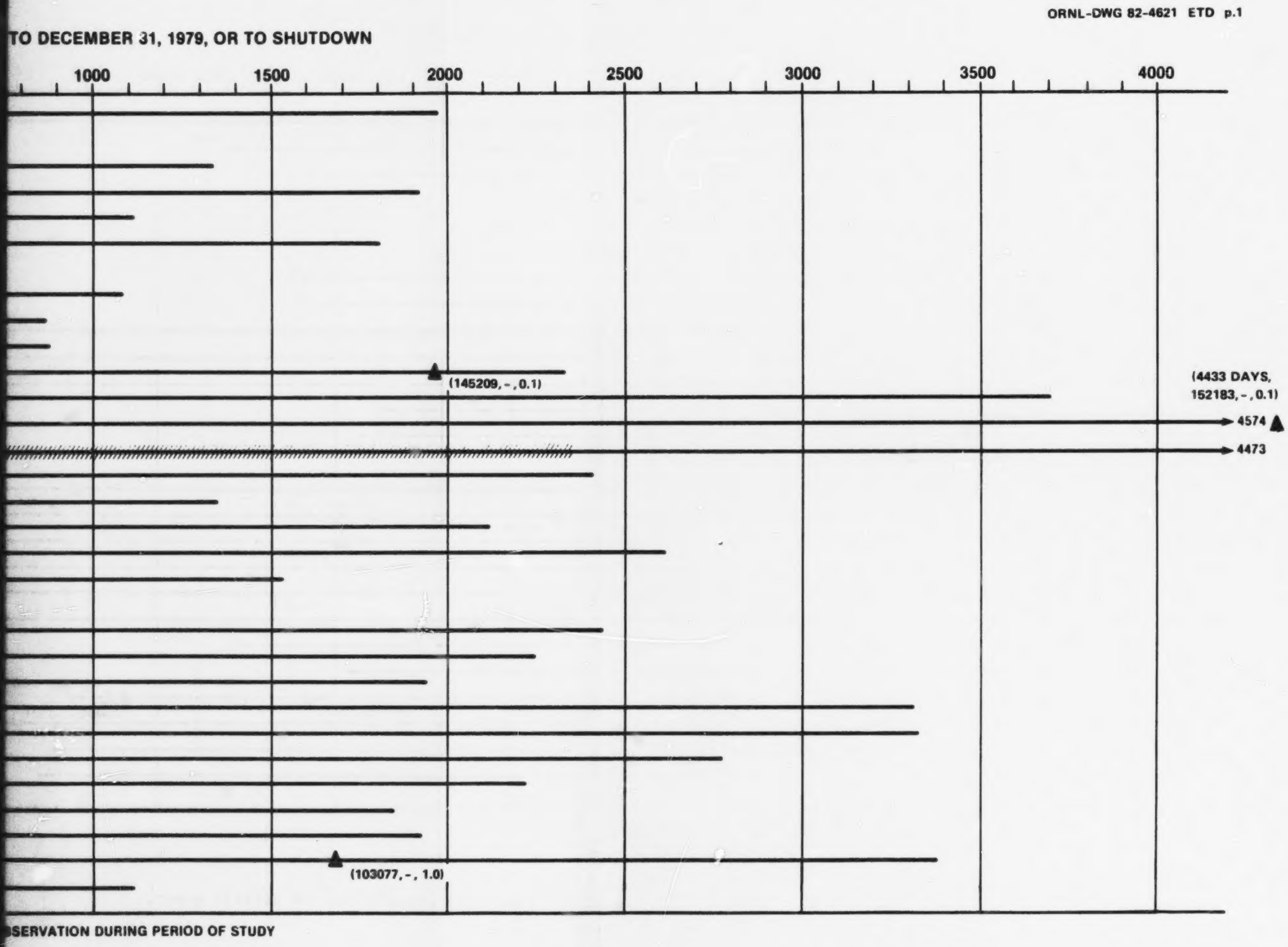

Fig. E.3. Time line for PWR small loss-of-coolant accident.

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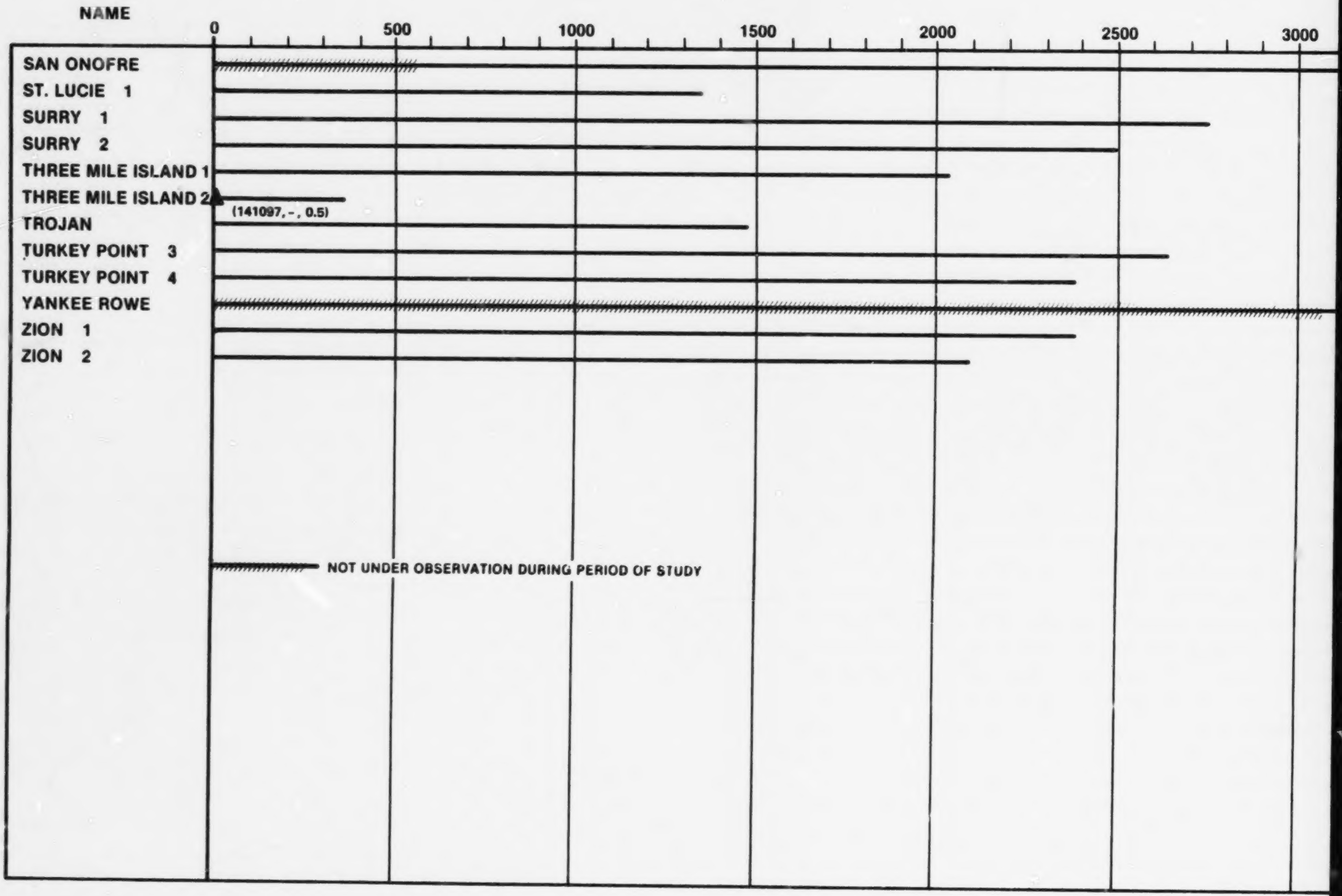

Fig. E.3 (continued)

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ORNL-DWG 82-4621 ETD p.2

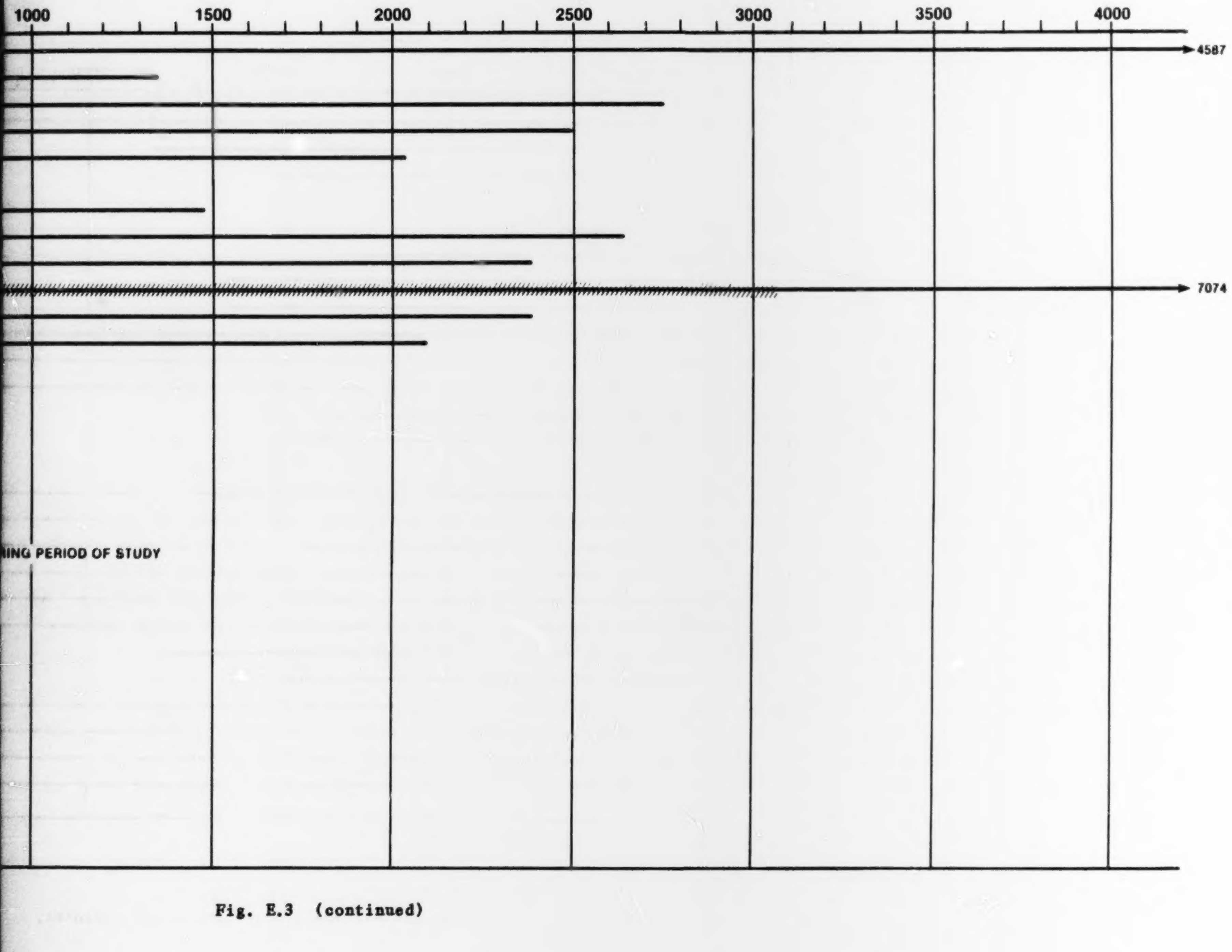

Fig. E.3 (continued)

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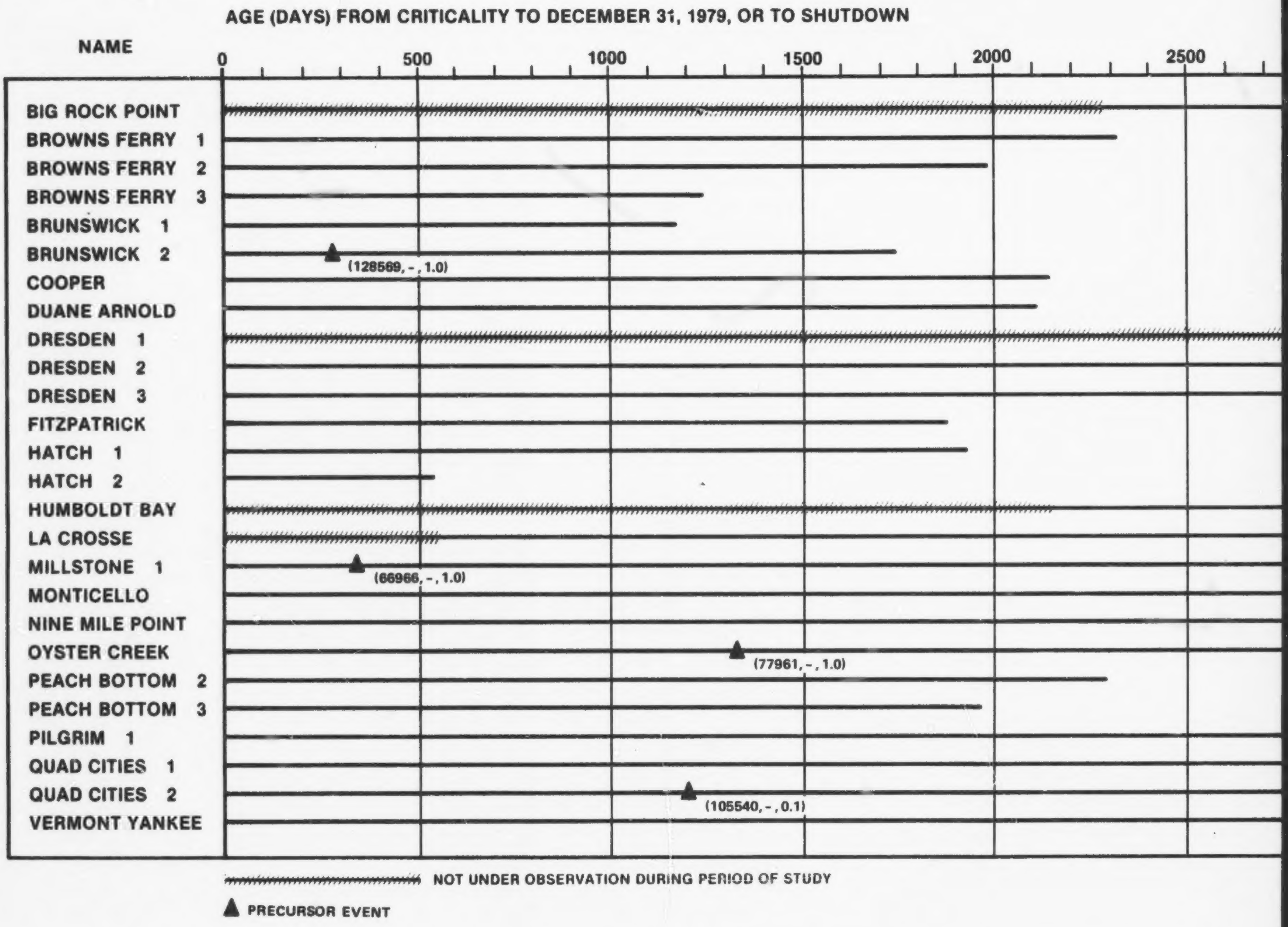

Fig. E.4. Time line for BWR small loss-of-coolant accident.

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BEST DOCUMENT

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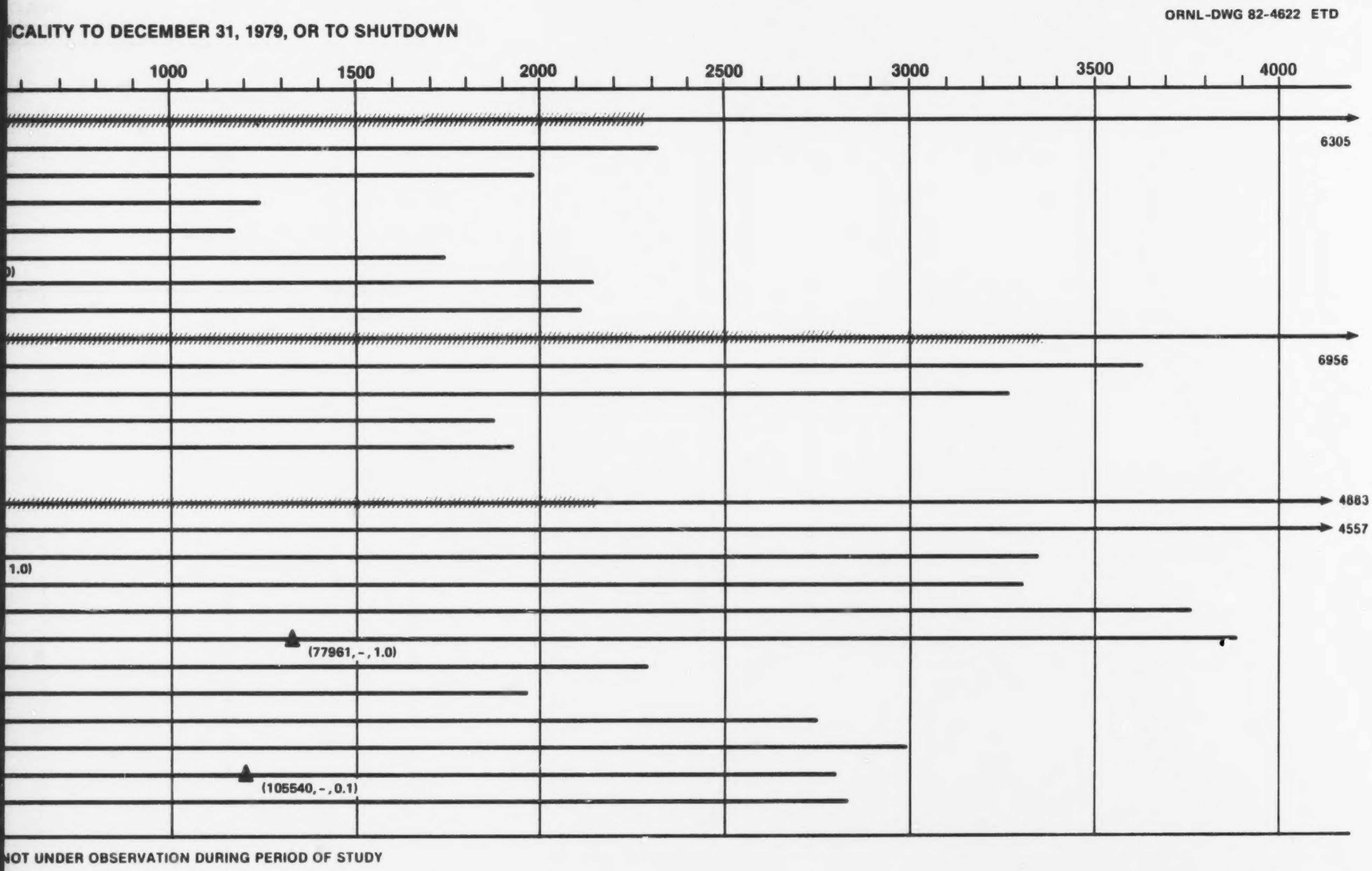

Fig. E.4. Time line for BWR small loss-of-coolant accident.

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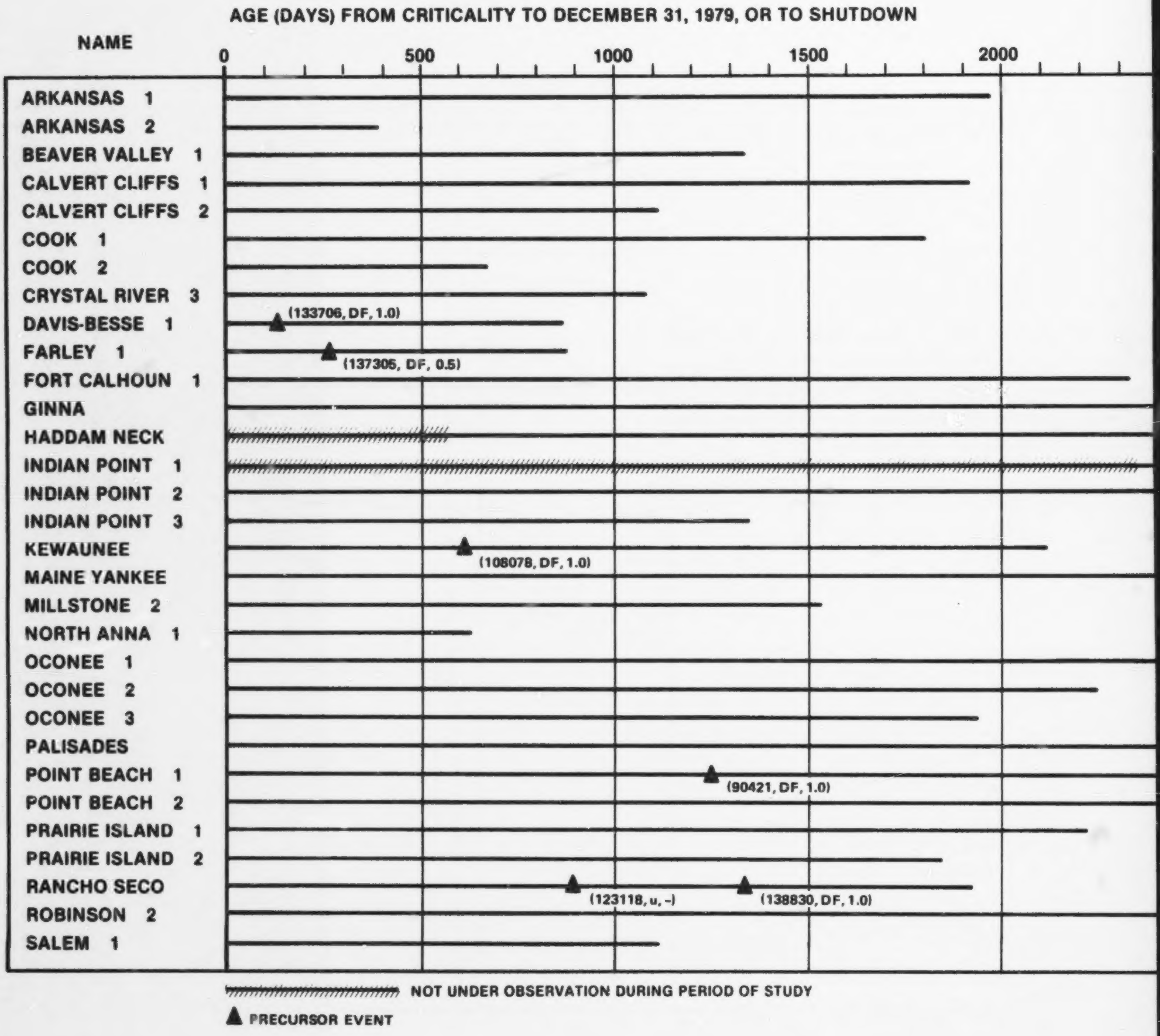

Fig. E.5. Time line for PWR failure of auxiliary fee

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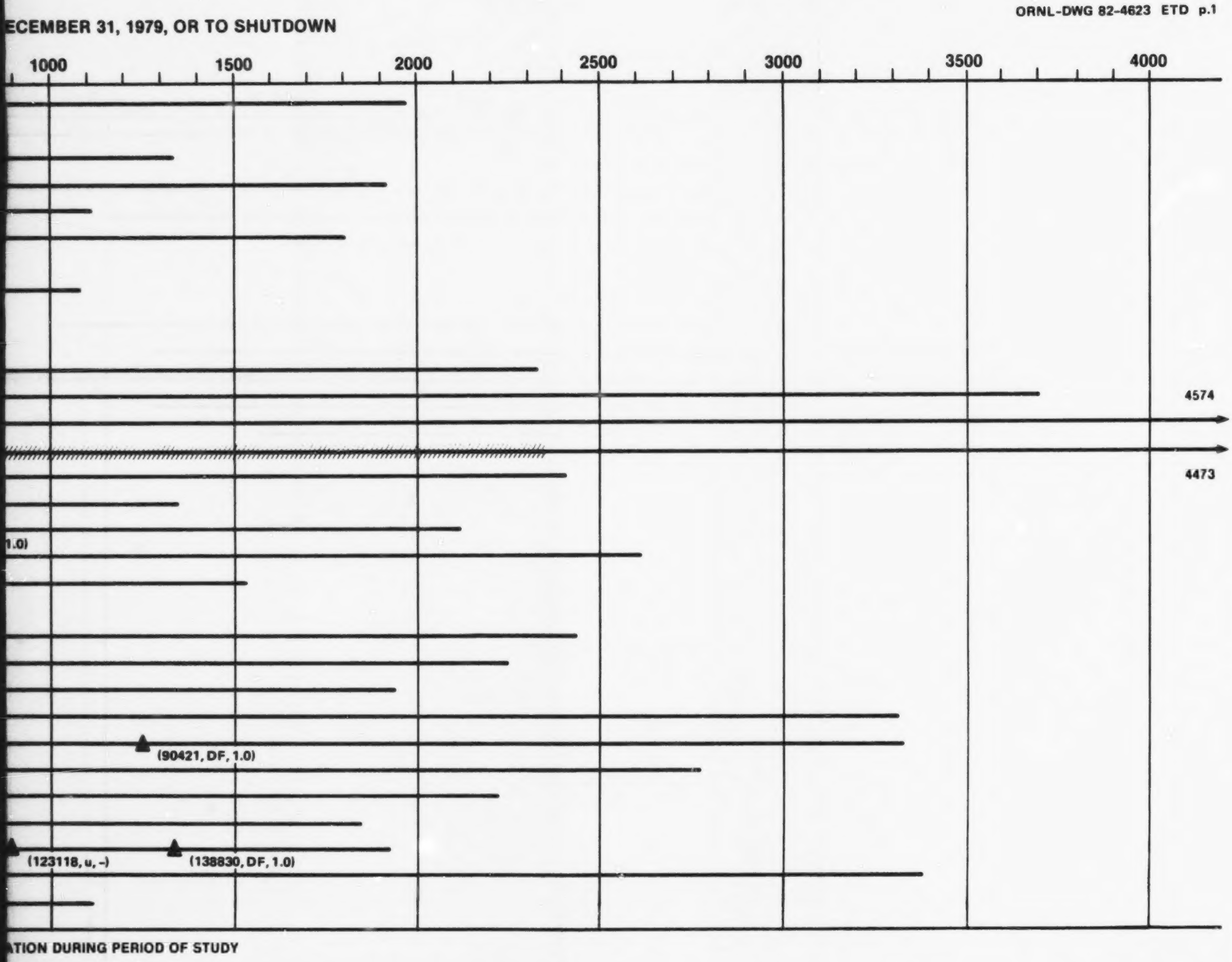

Fig. E.5. Time line for PWR failure of auxiliary feedwater.

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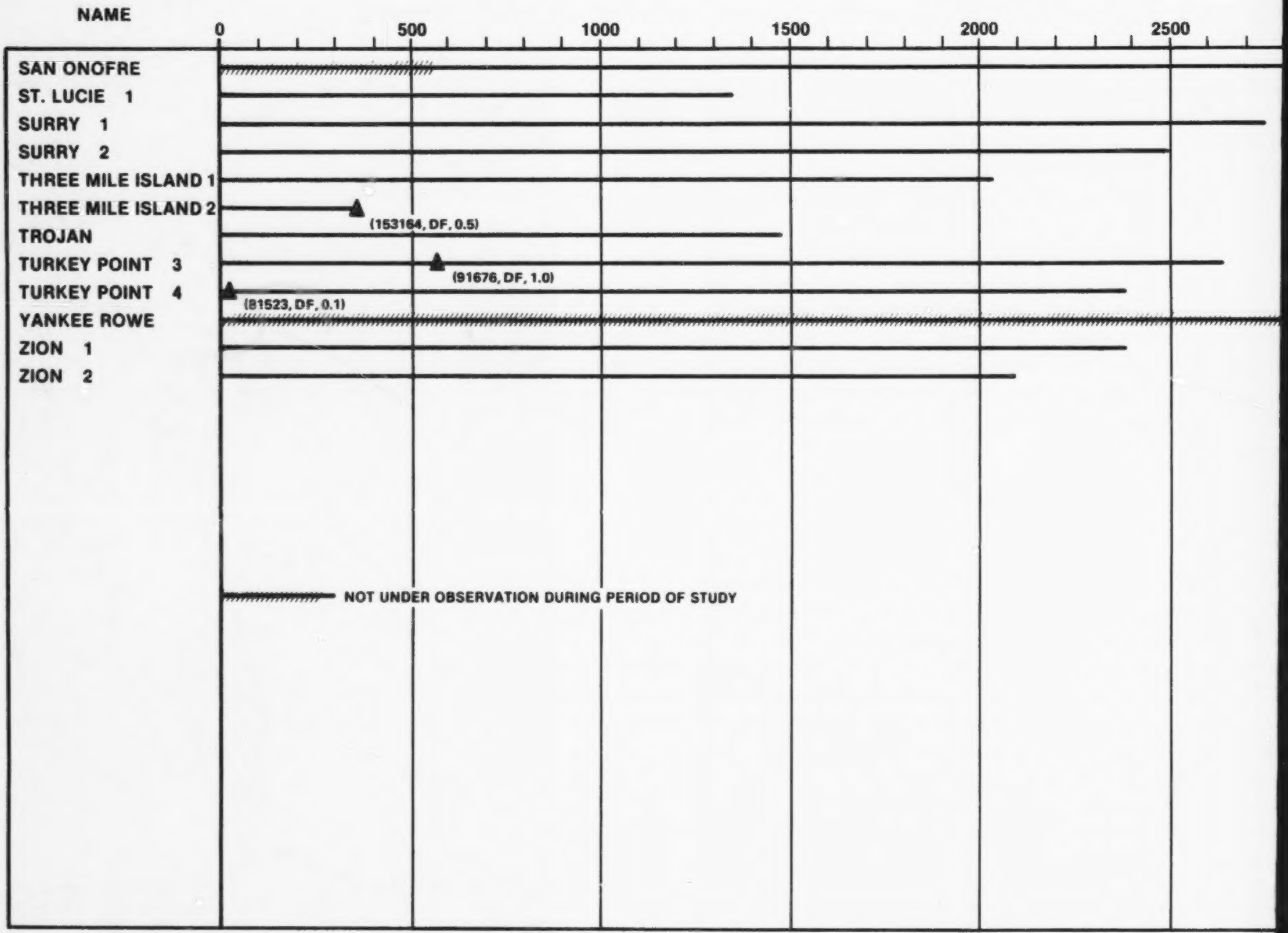

Fig. E.5 (continued)

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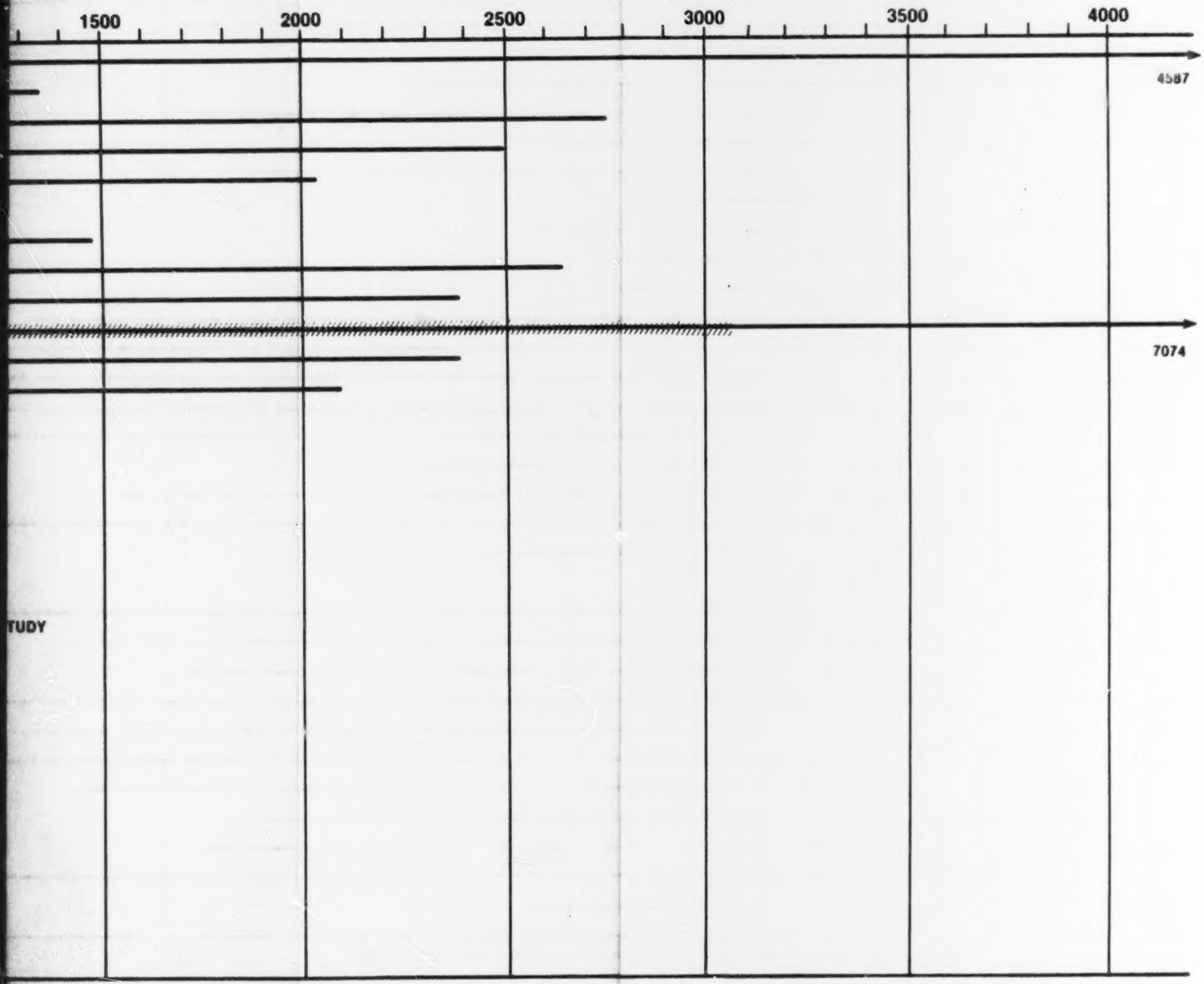

Fig. E.5 (continued)

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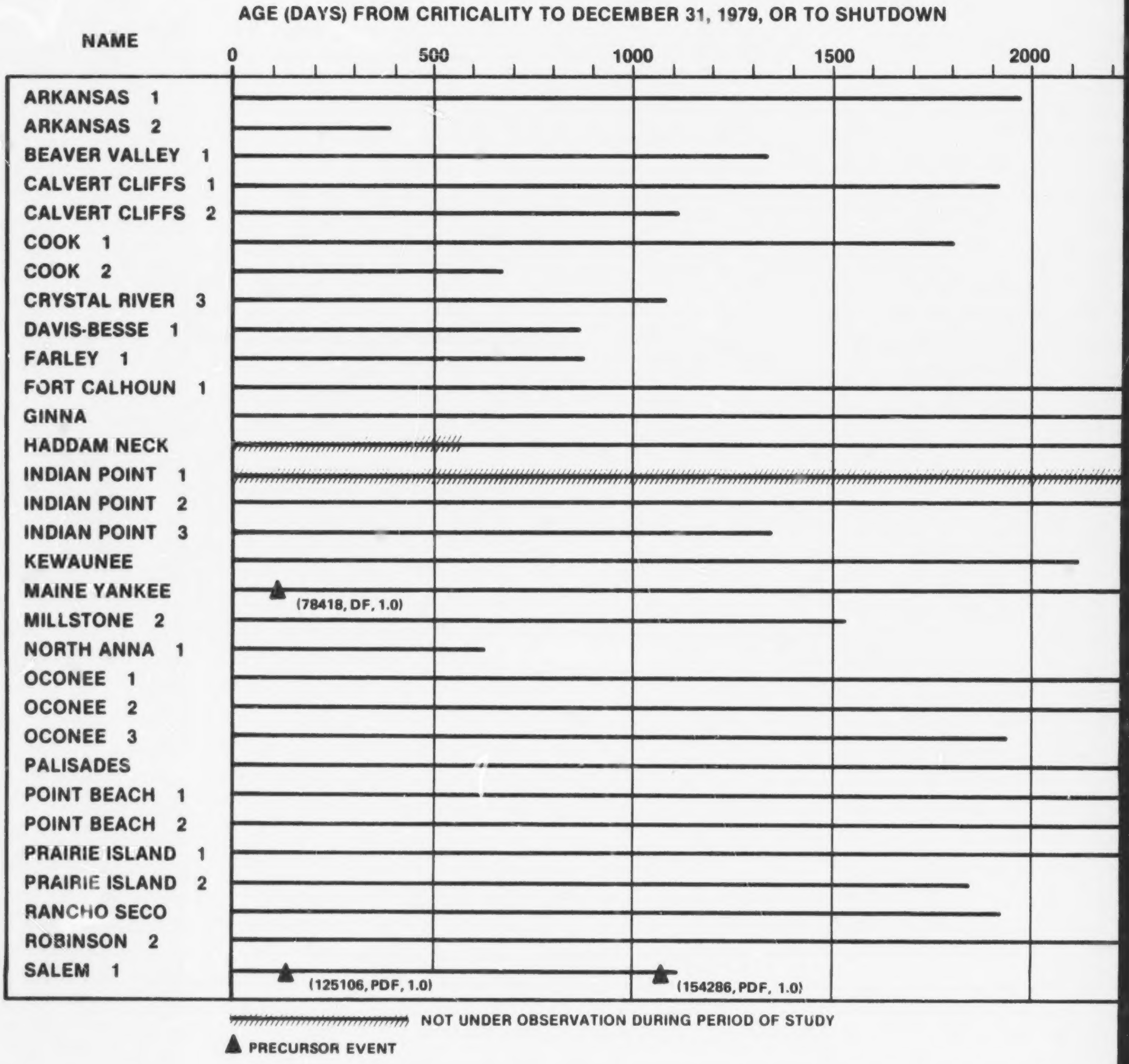

Fig. E.6. Time line for PWR failure of high-

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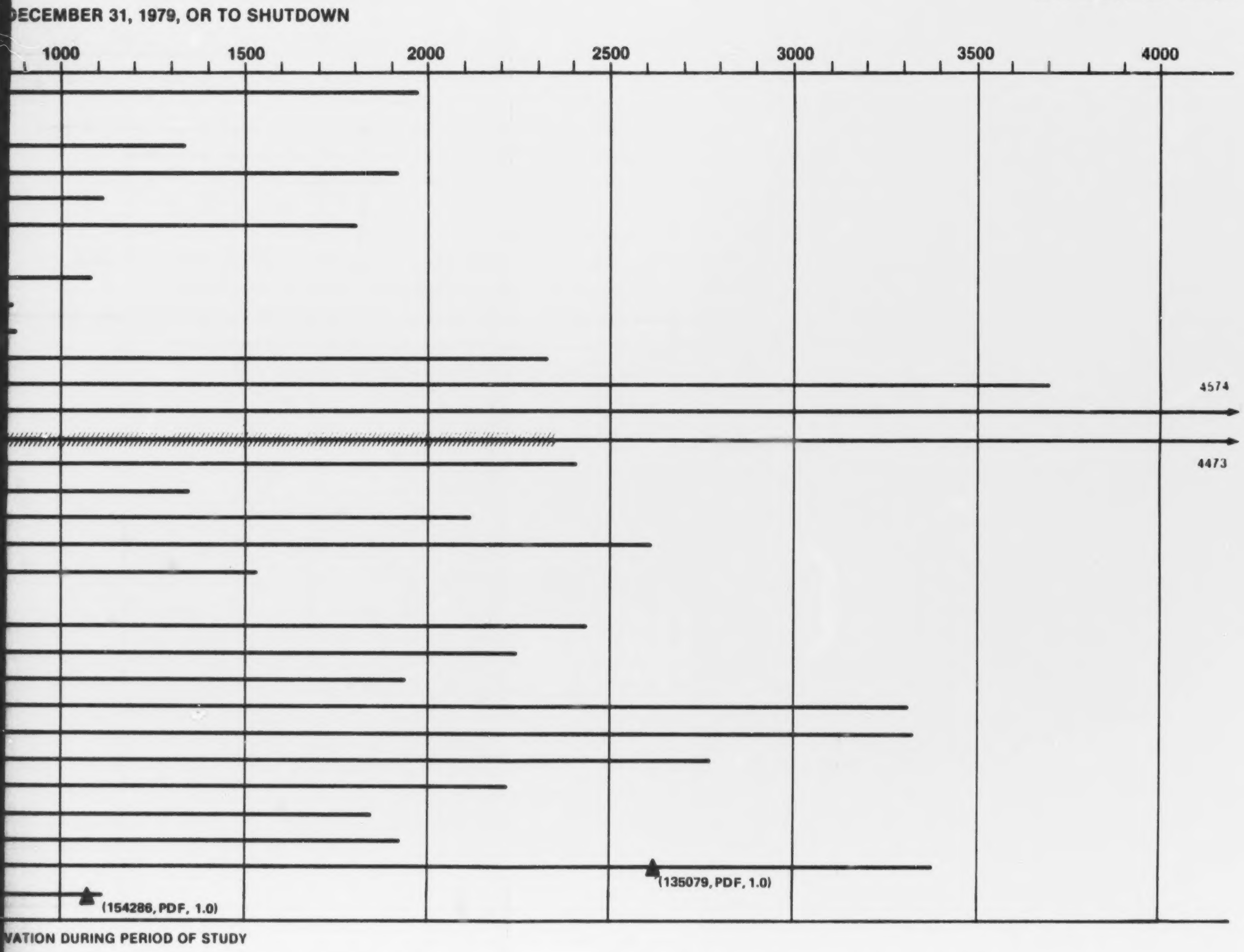

Fig. E.6. Time line for PWR failure of high-pressure injection.

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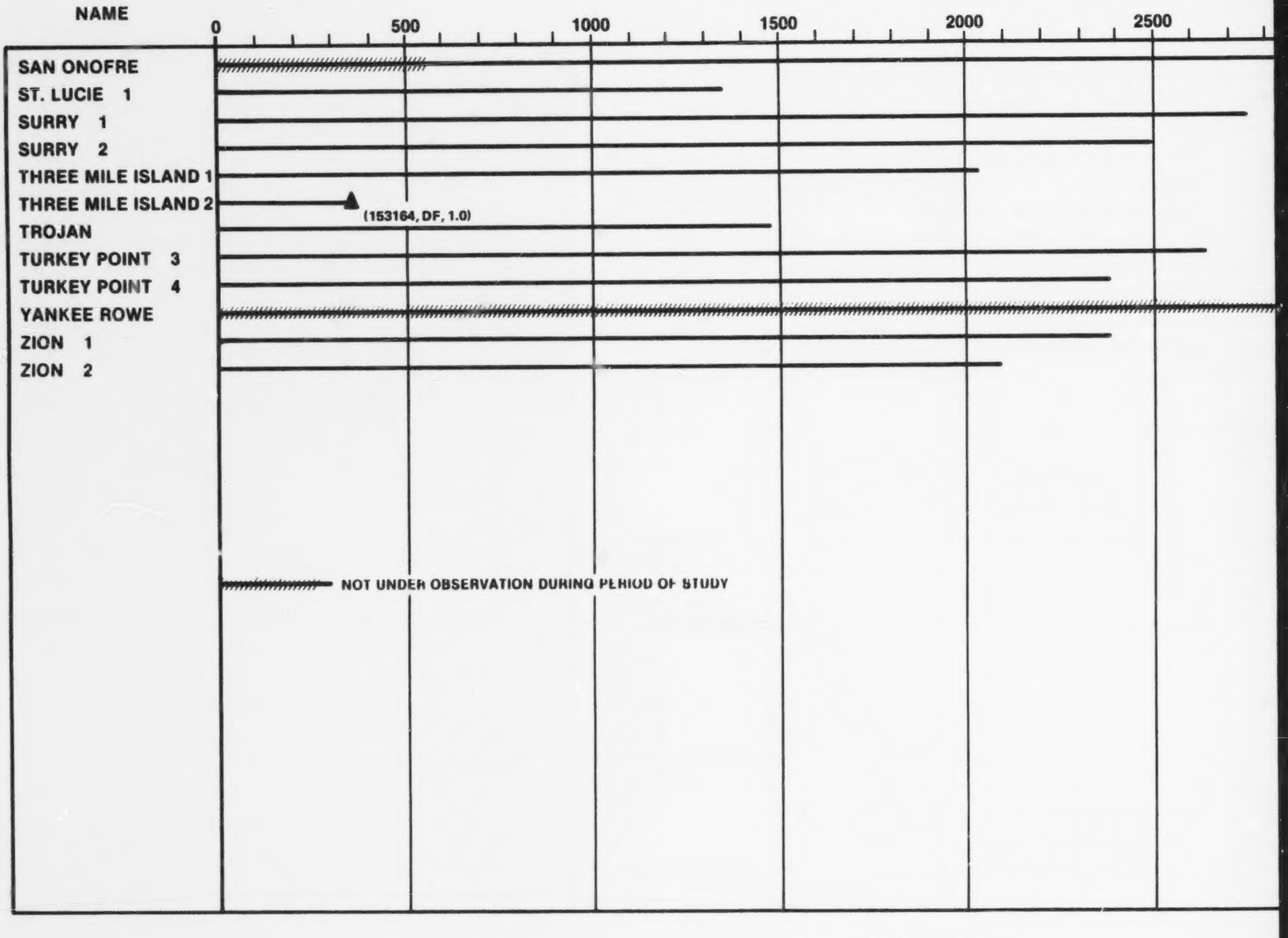

Fig. E.6 (continued)

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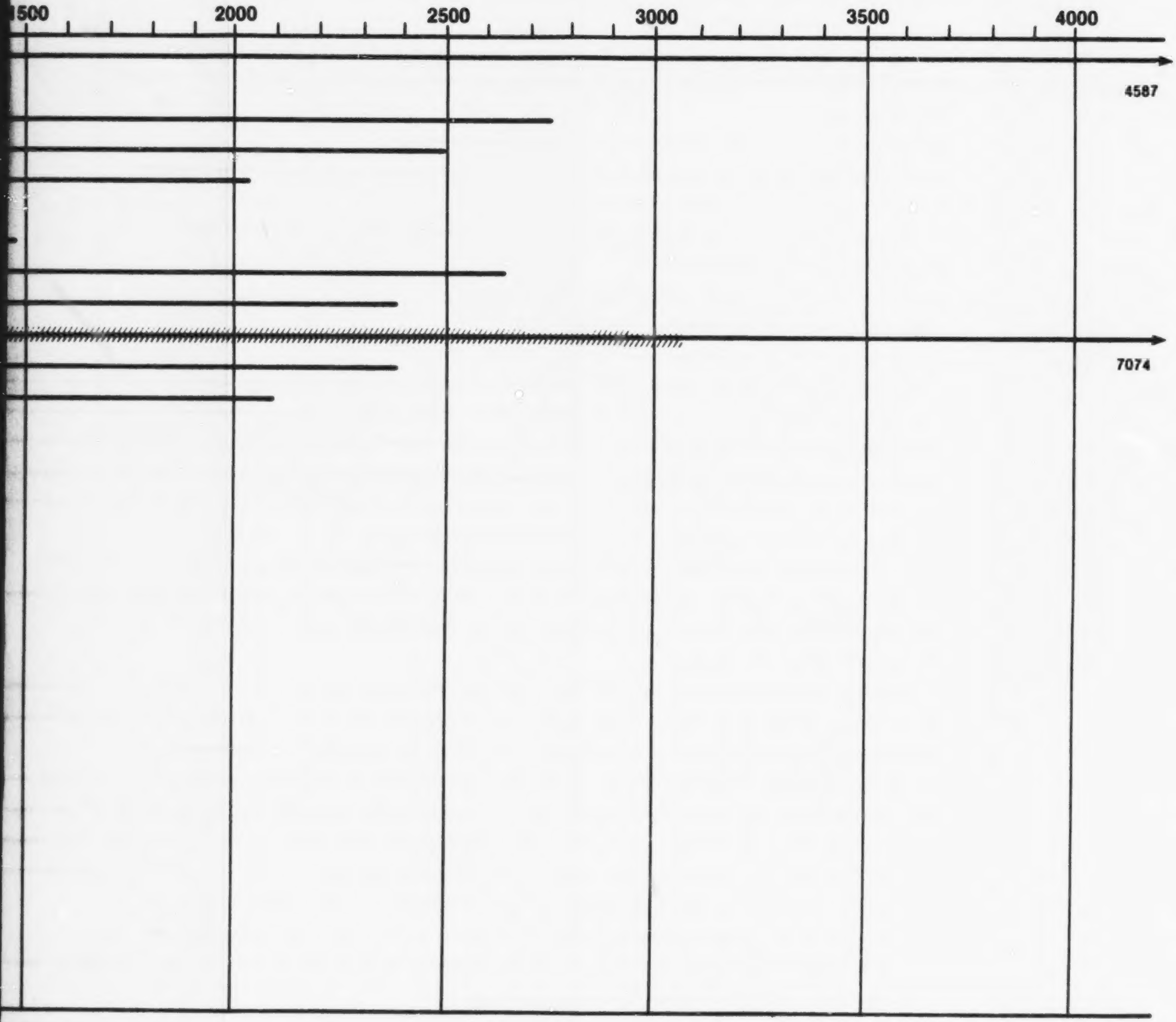

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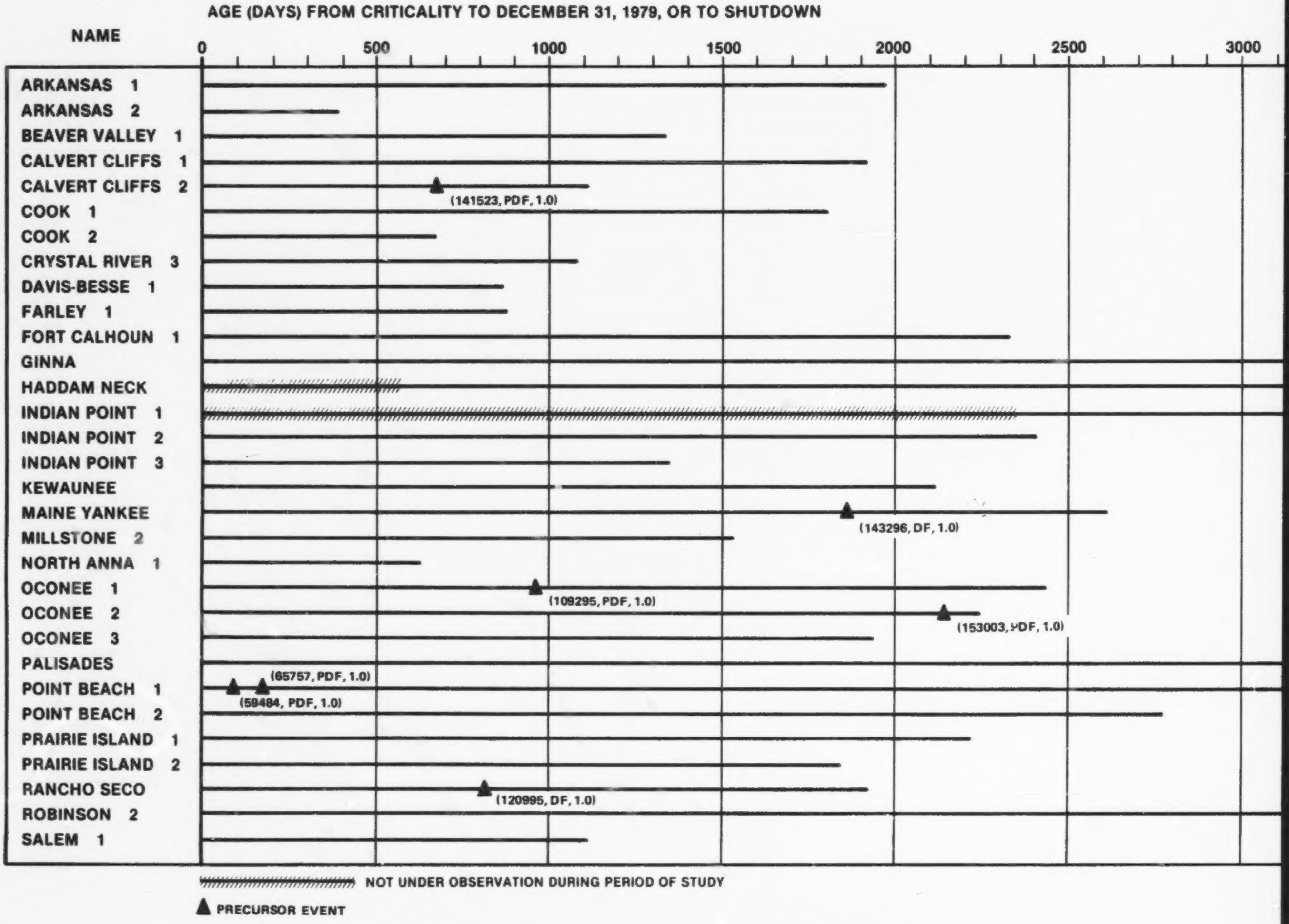

Fig. E.7. Time line for PWR failure of long-term core cooling (sump recirculation).

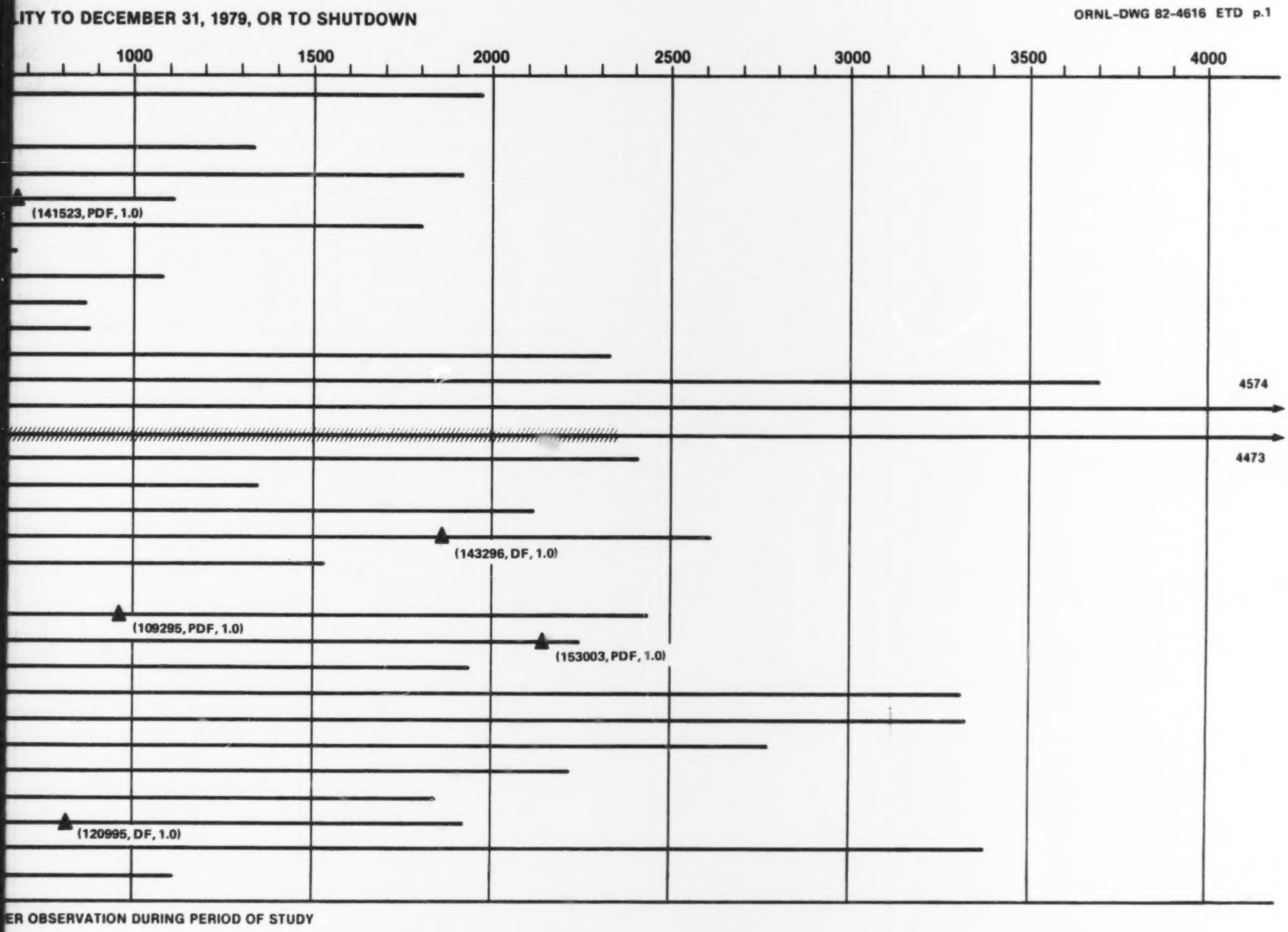

Fig. E.7. Time line for PWR failure of long-term core cooling (sump recirculation).

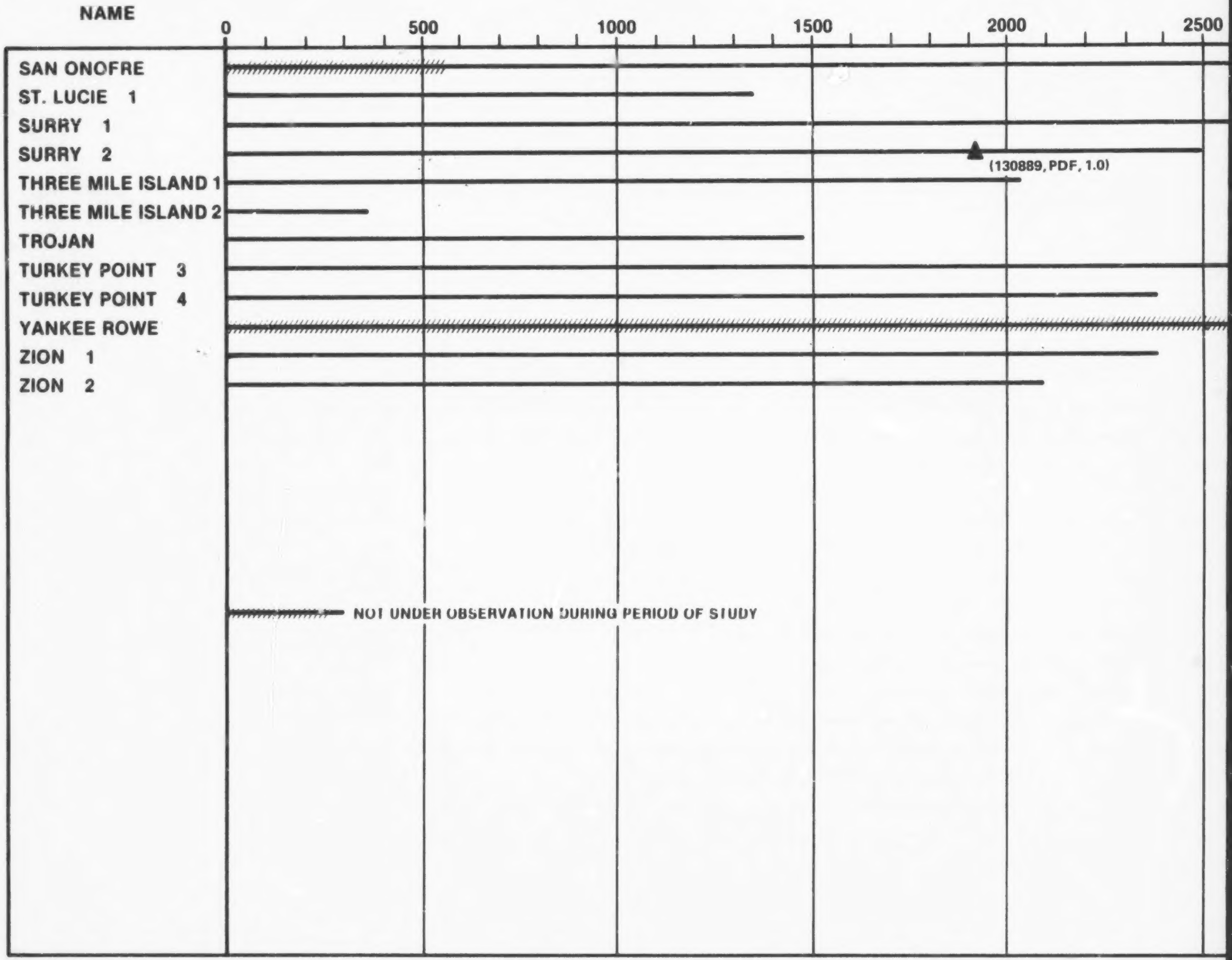

Fig. E.7 (continued)

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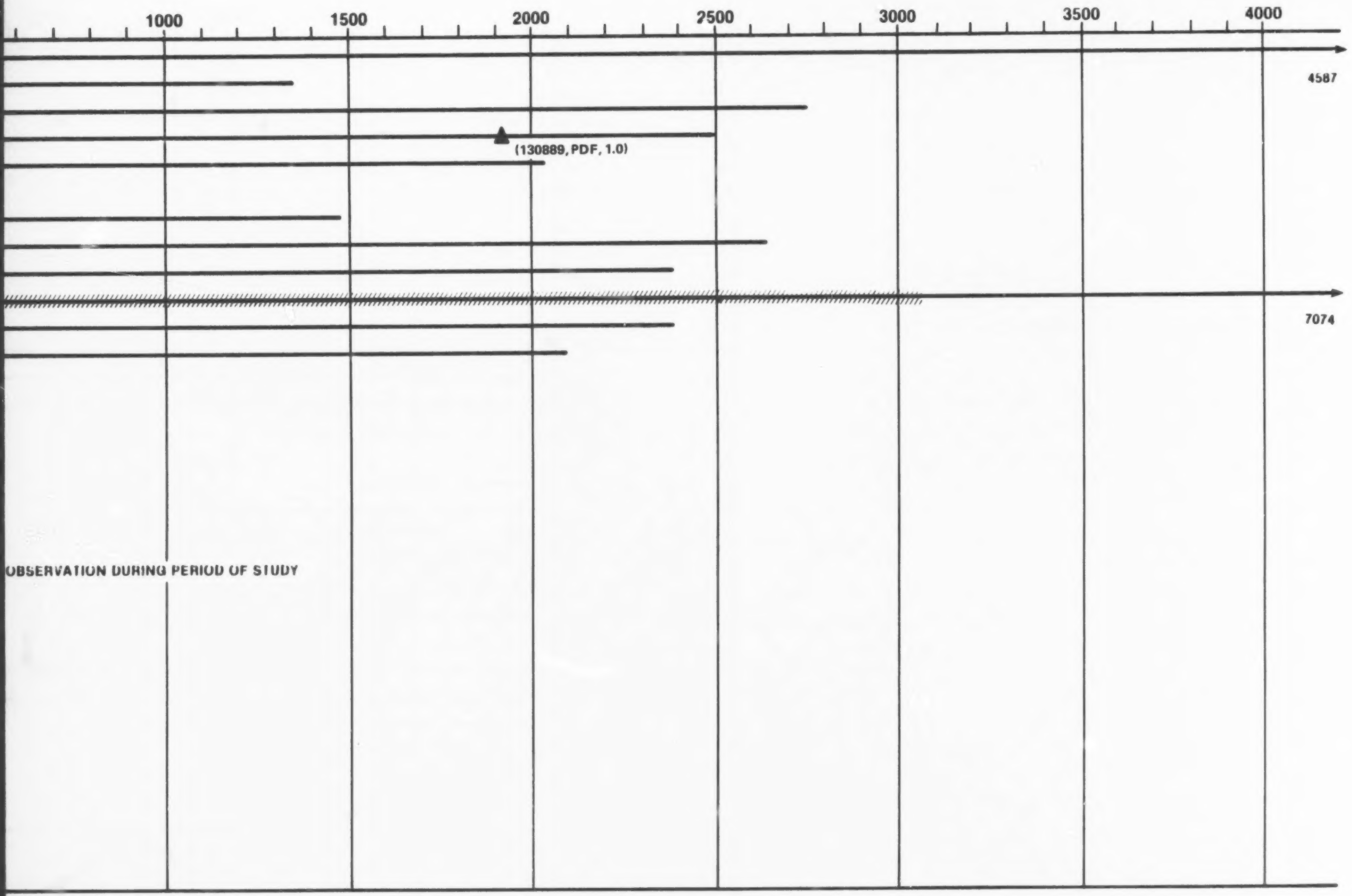

Fig. E.7 (continued)

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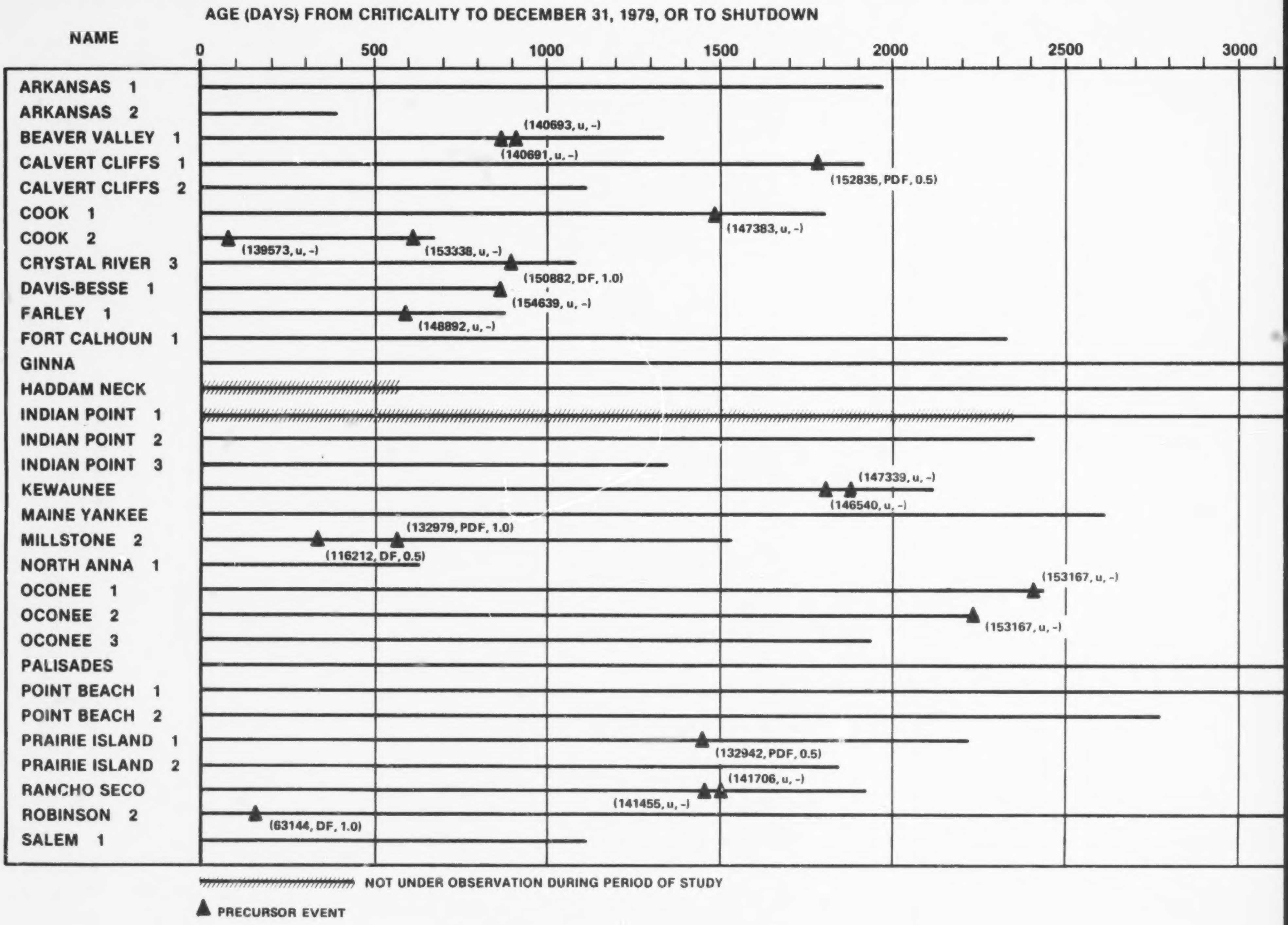

Fig. E.8. Time line for PWR failure of emergency power.

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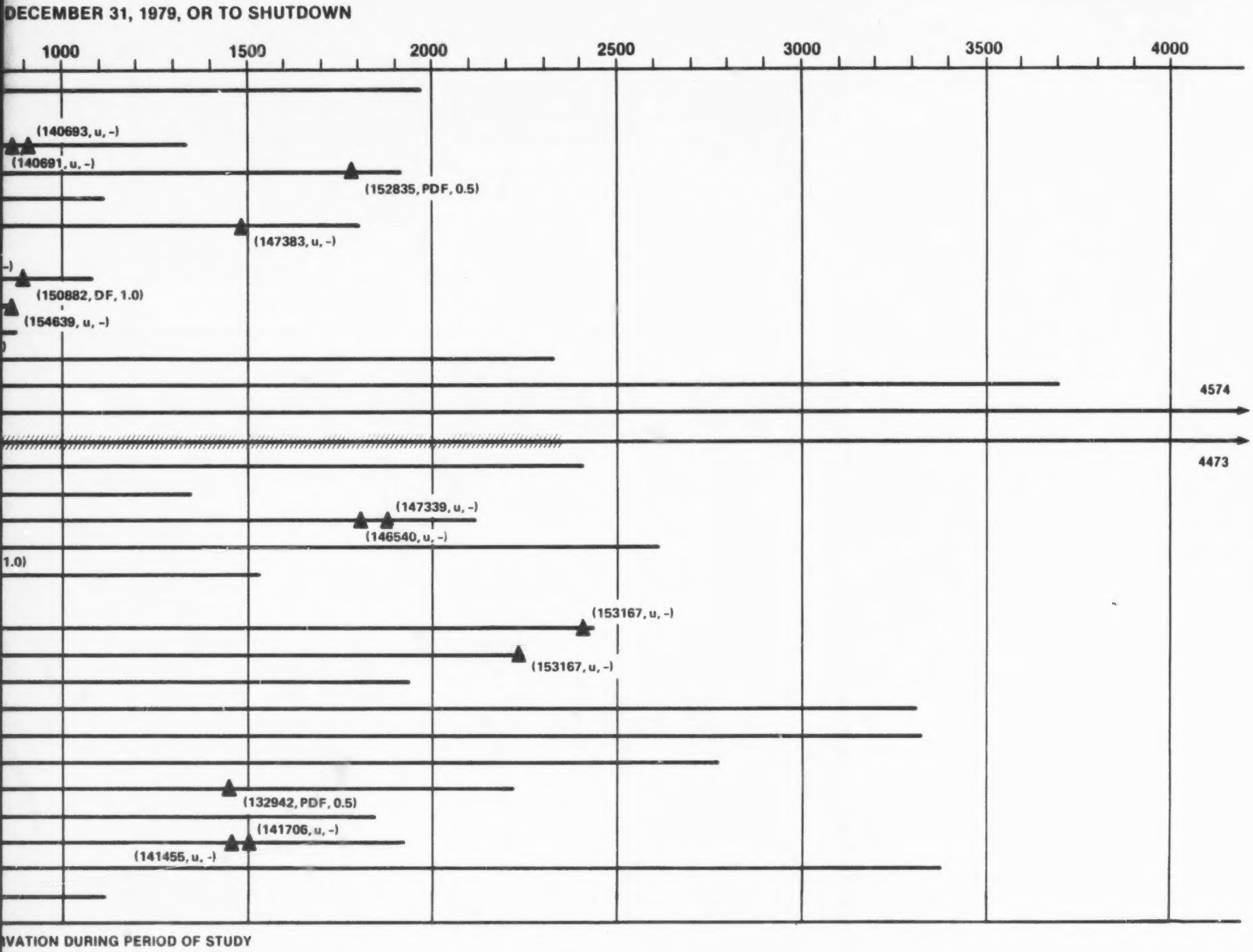

Fig. E.8. Time line for PWR failure of emergency power.

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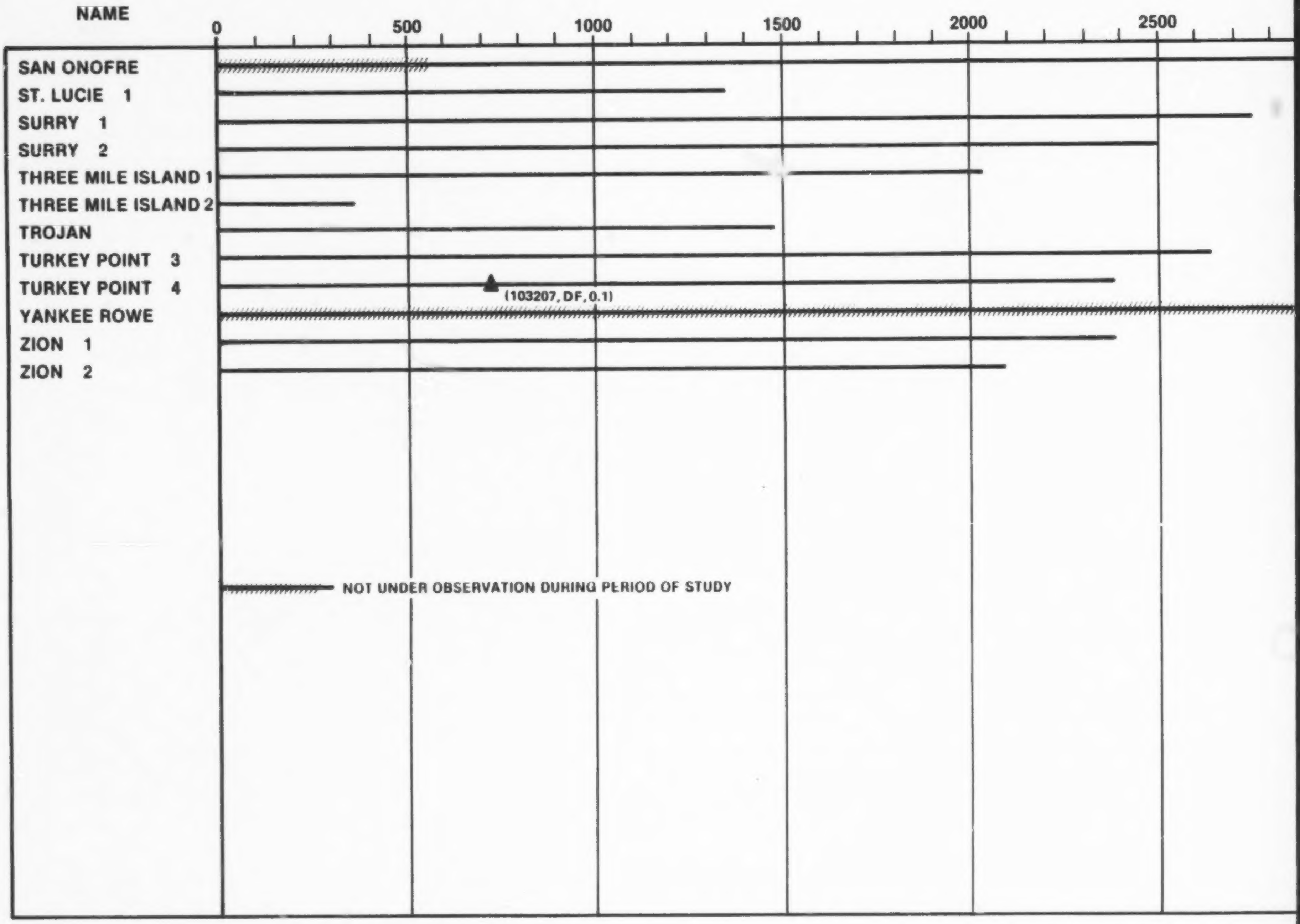

Fig. E.8 (continued)

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ORNL-DWG 82-4617 ETD p.2

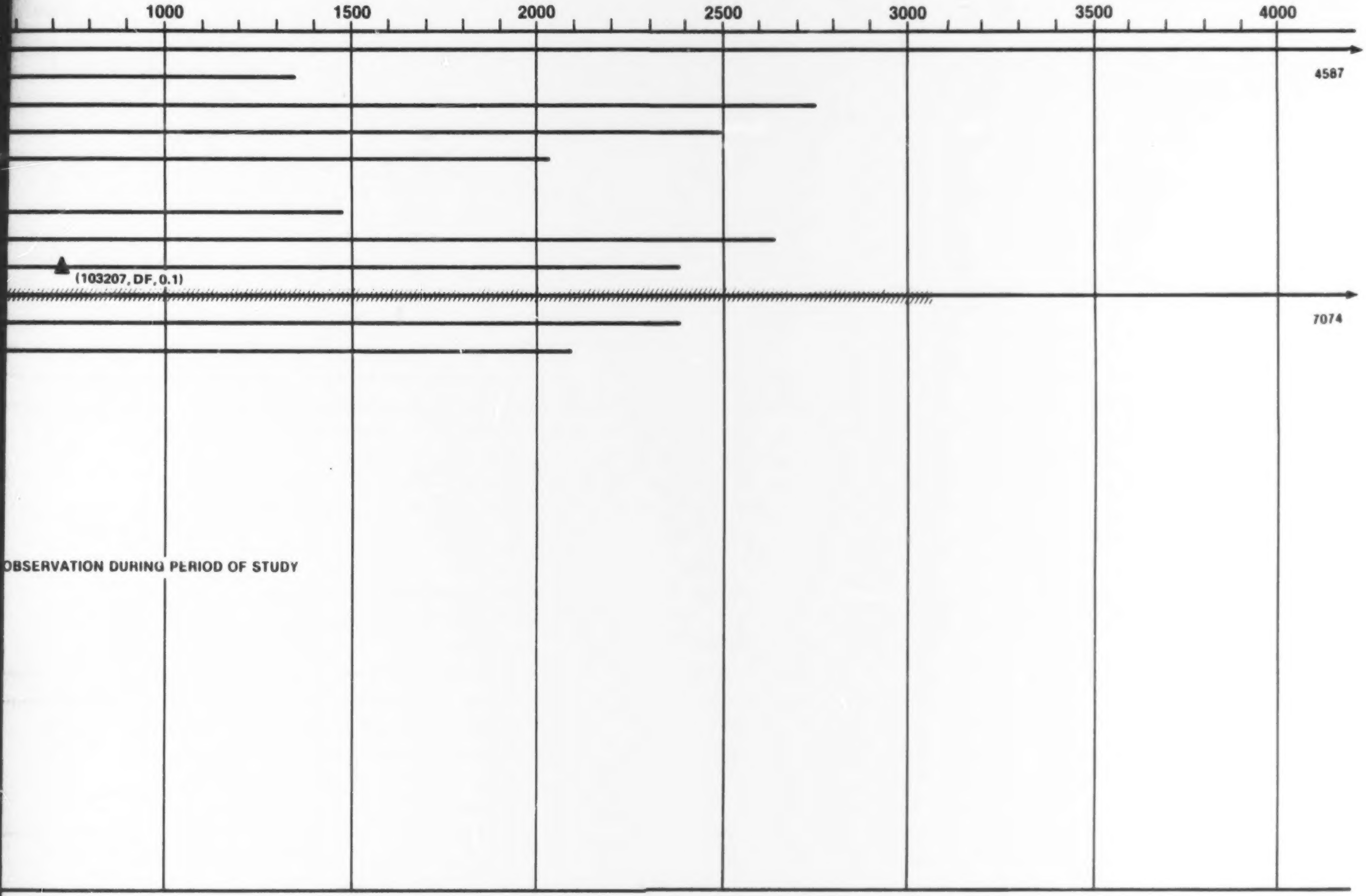

Fig. E.8 (continued)

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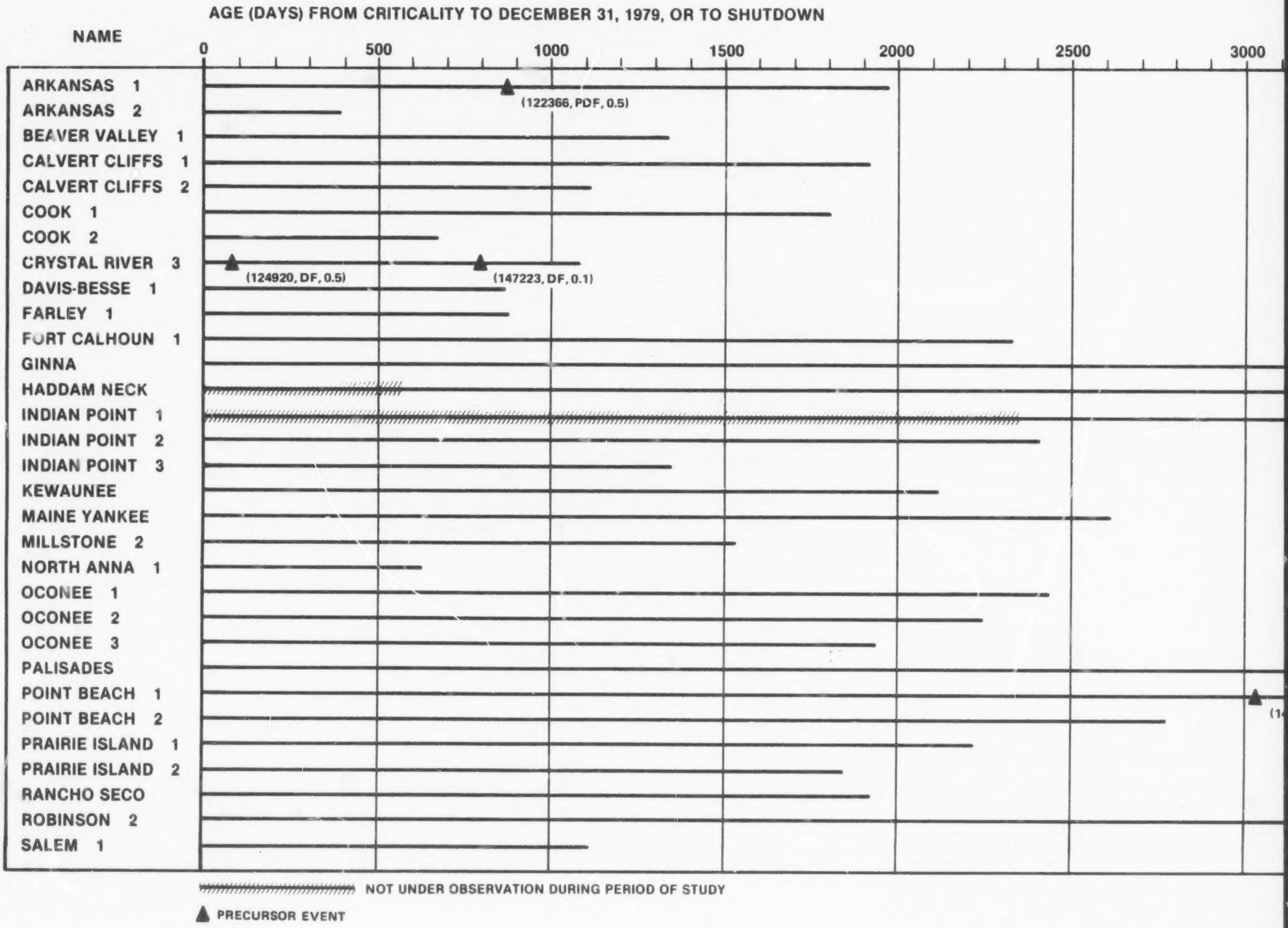

Fig. E.9. Time line for PWR failure of steam generator isolation.

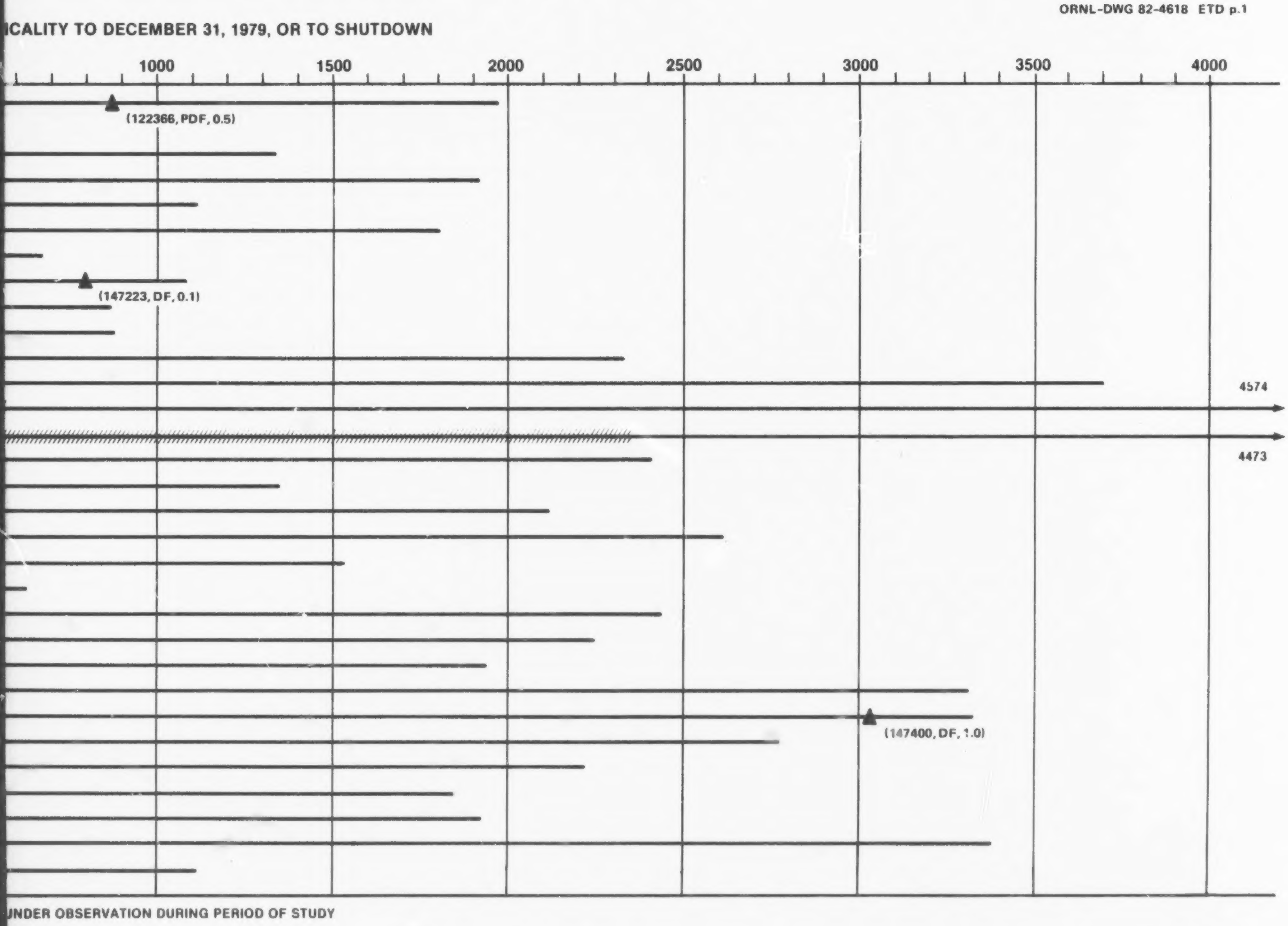

Fig. E.9. Time line for PWR failure of steam generator isolation.

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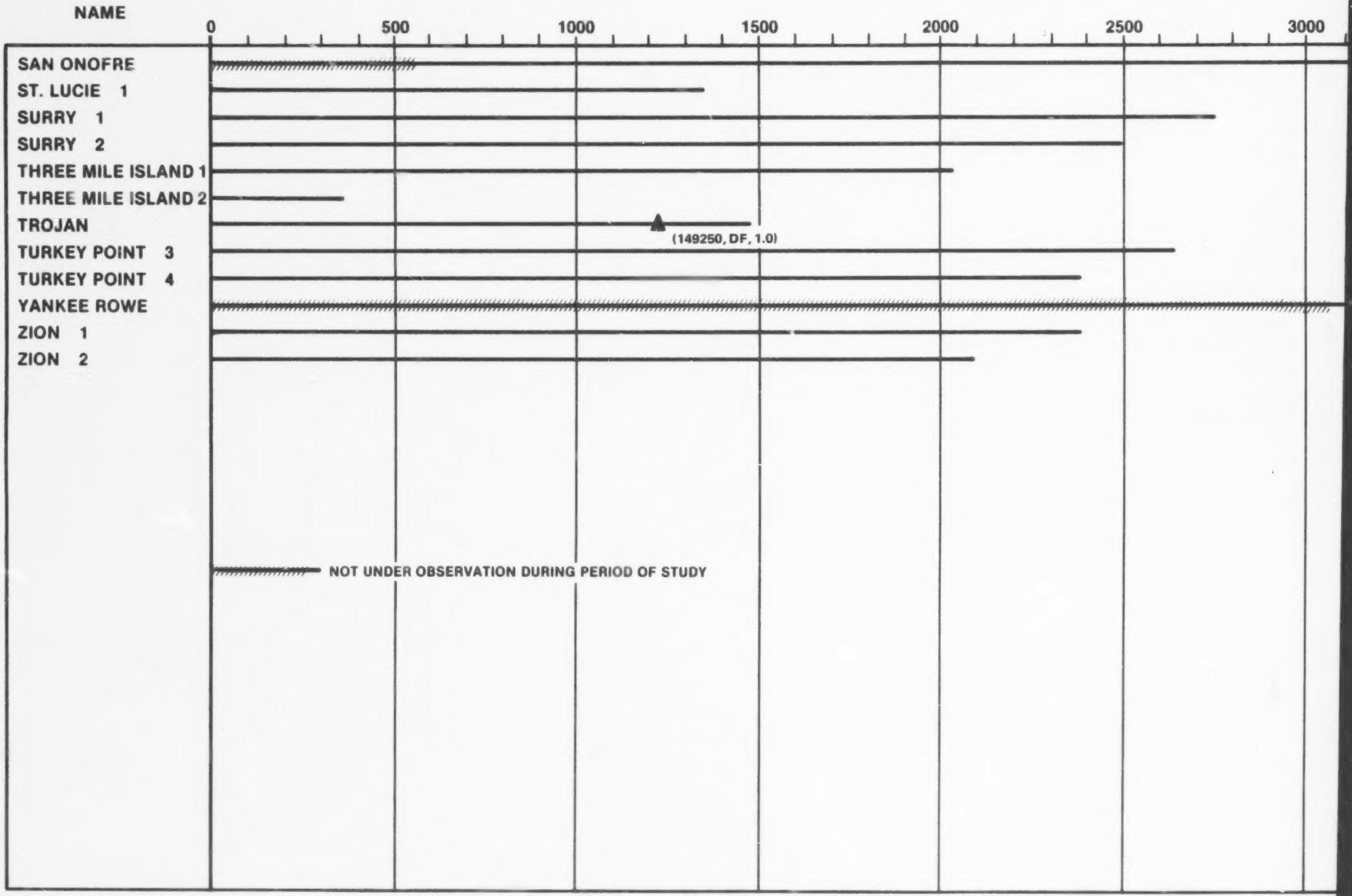

Fig. E.9 (continued)

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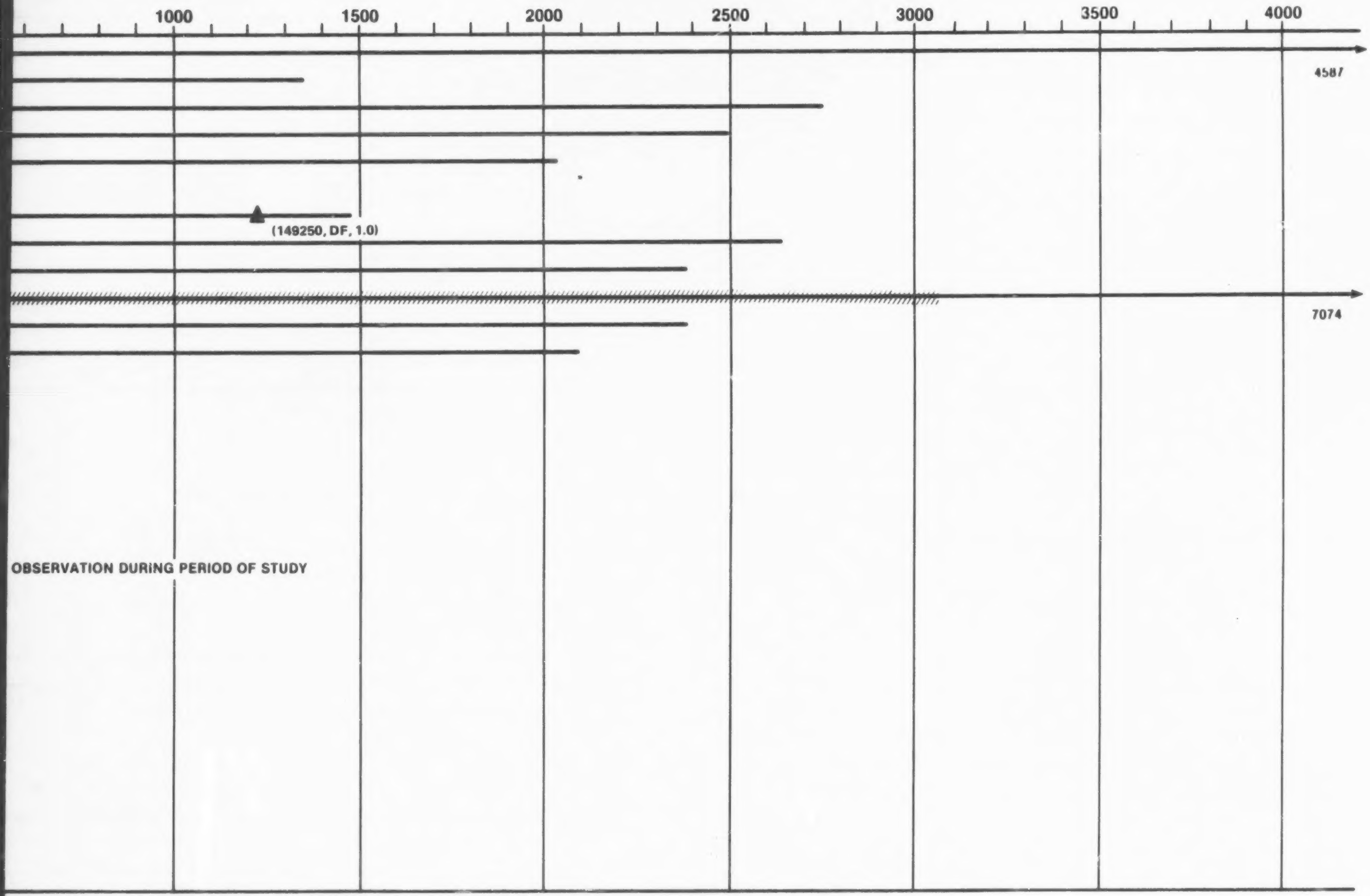

Fig. E.9 (continued)

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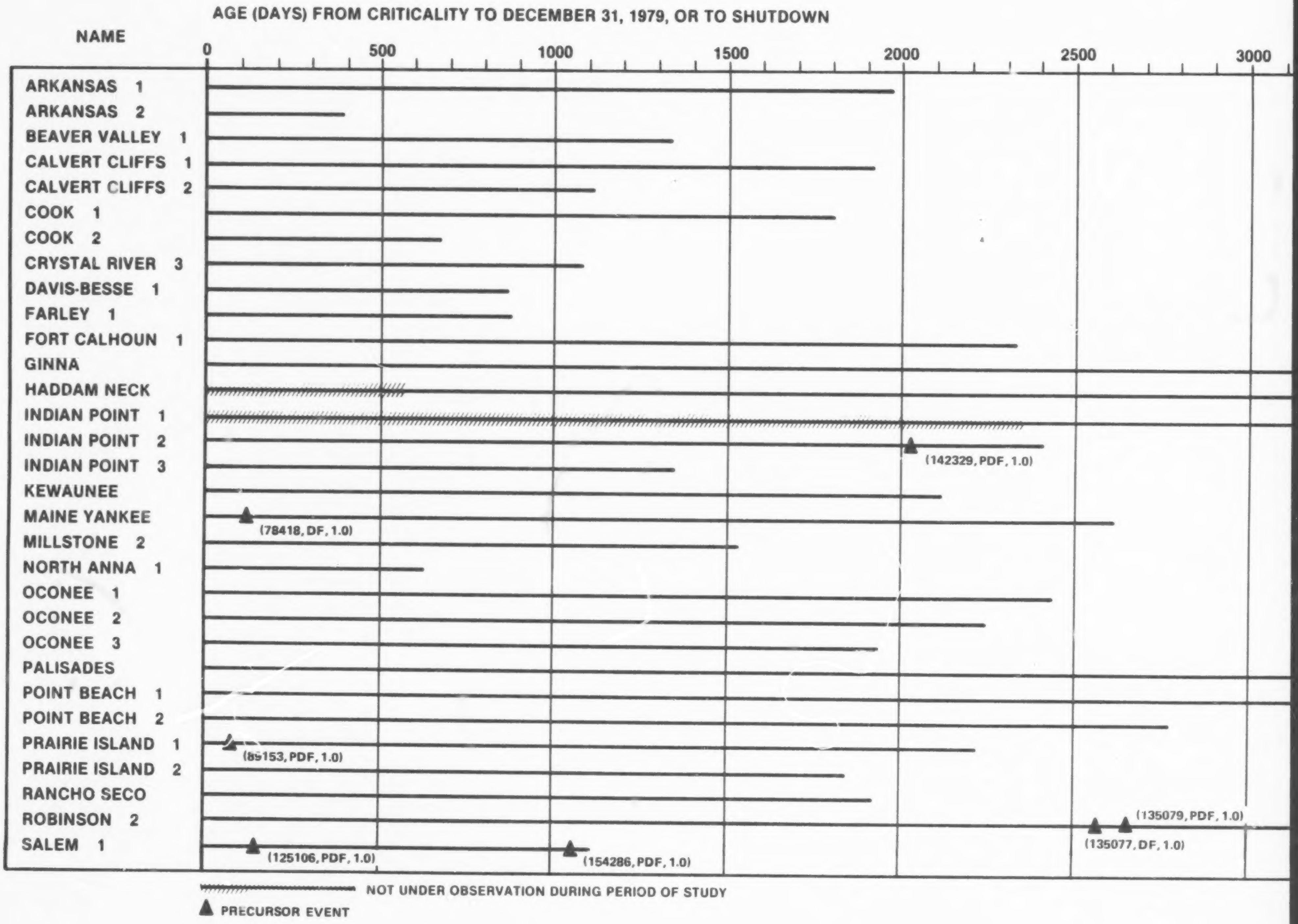
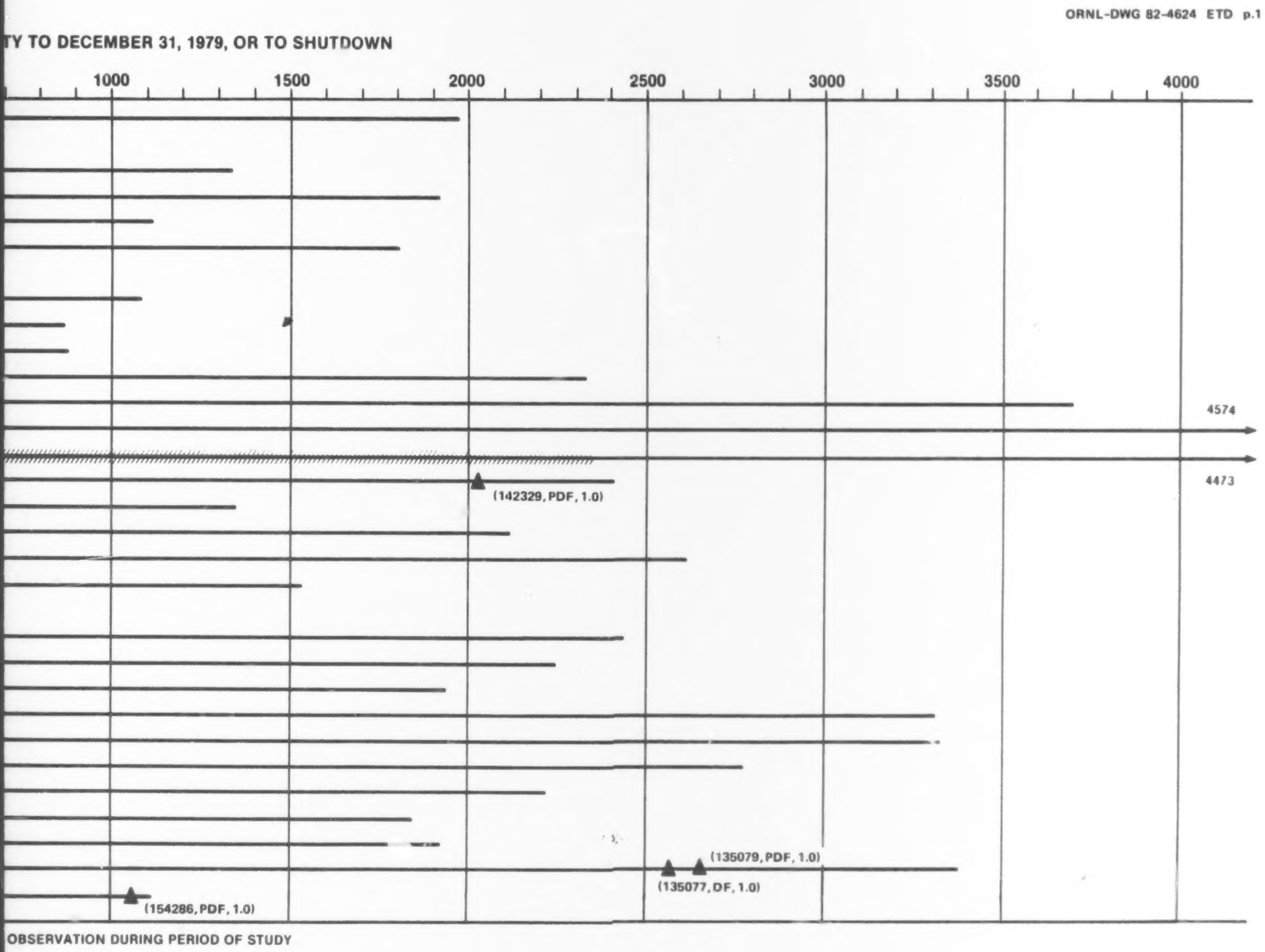


Fig. E.10. Time line for PWR failure of high-pressure injection for steam line break mitigatio



0. Time line for PWR failure of high-pressure injection for steam line break mitigation.

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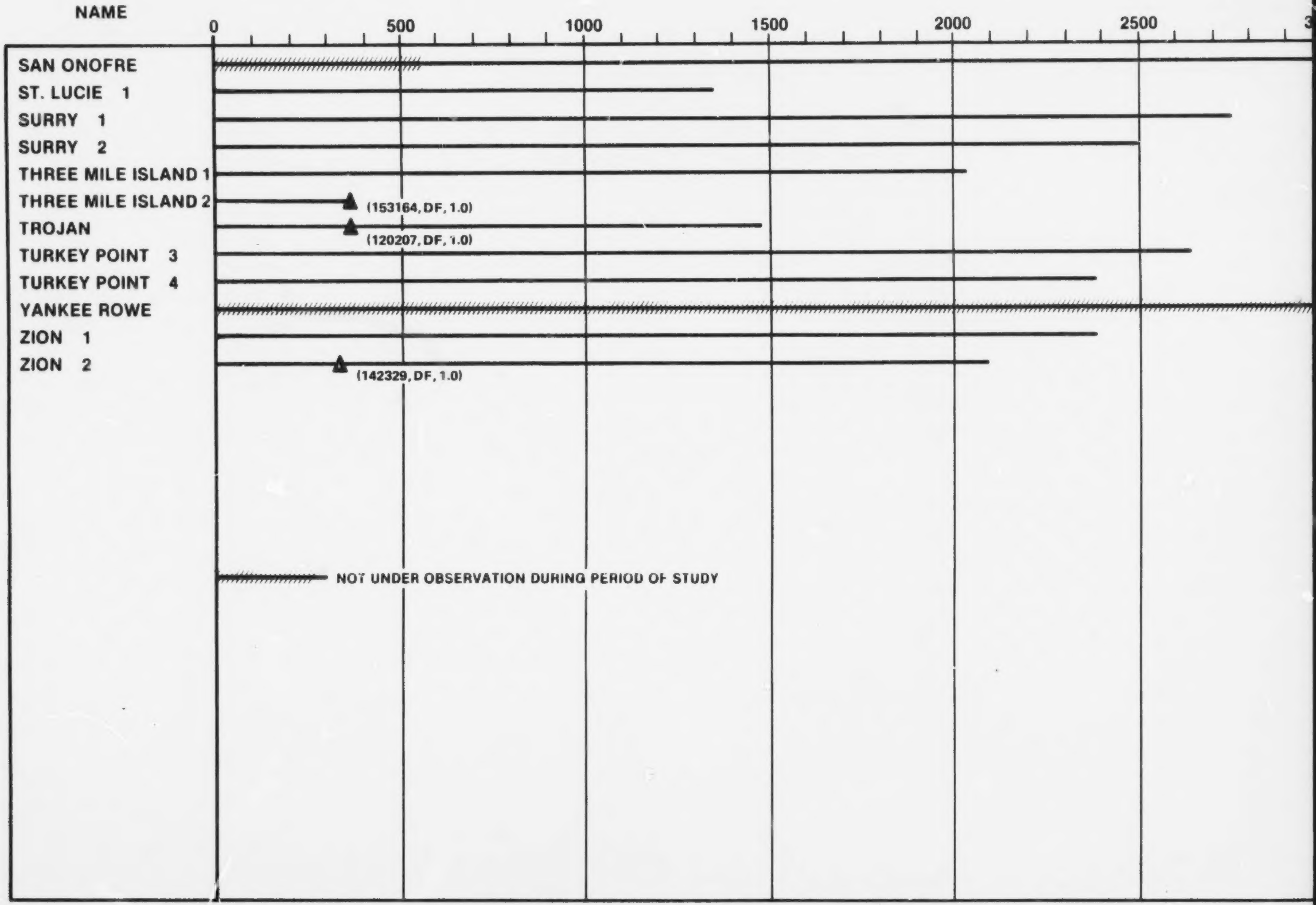

Fig. E.10 (continued)

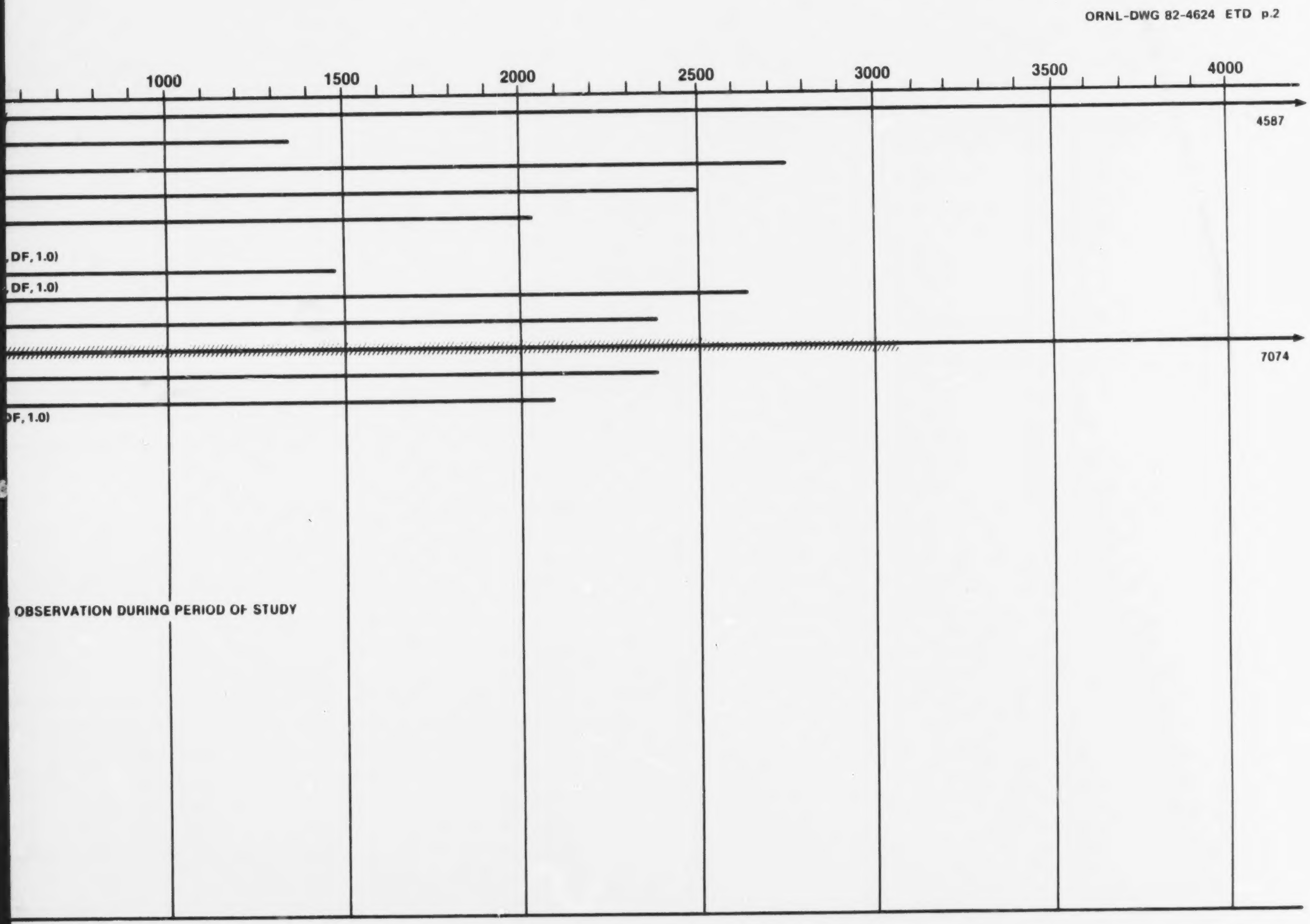

Fig. E.10 (continued)

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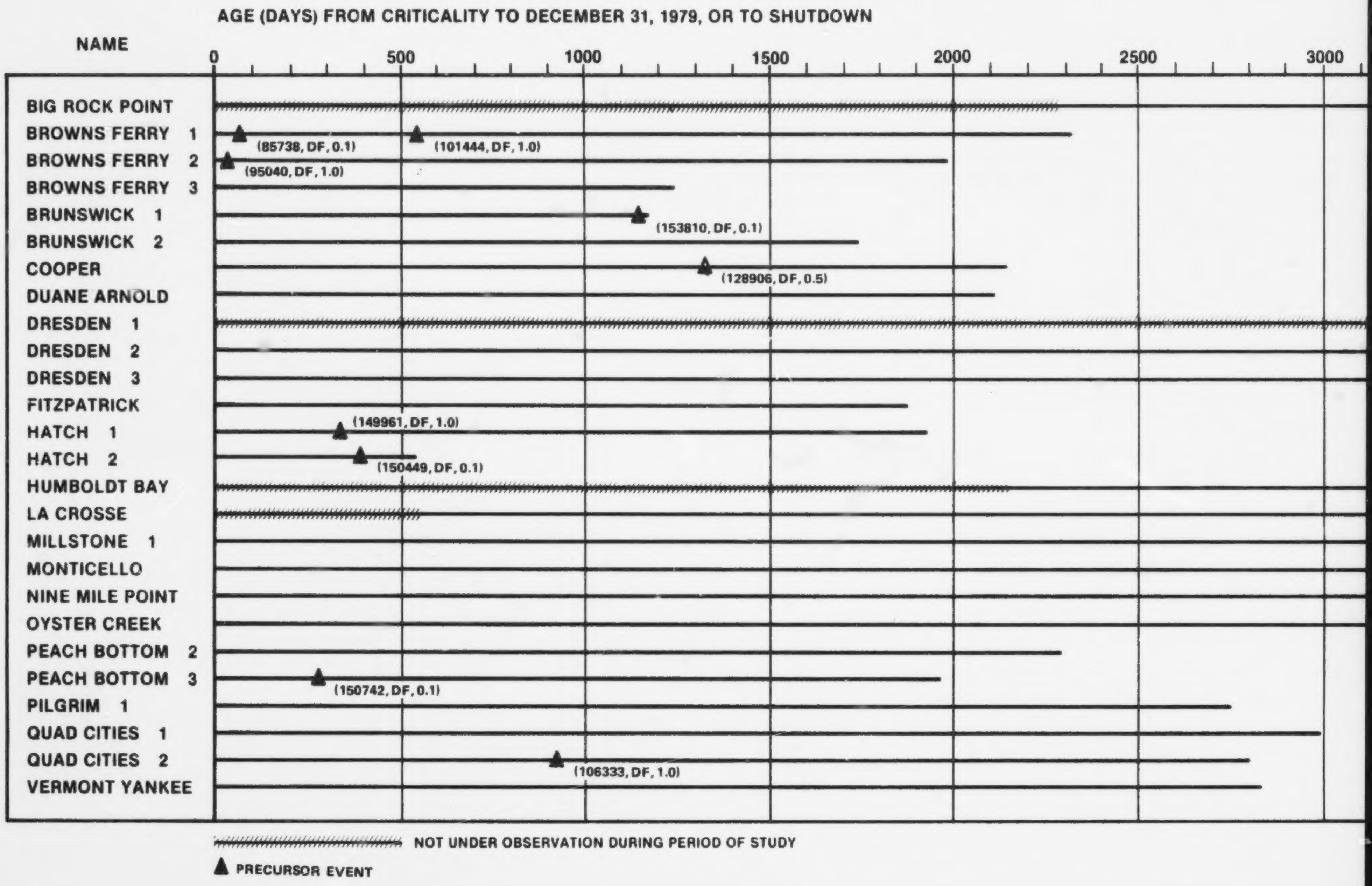

Fig. E.11. Time line for BWR failure of reactor core isolation cooling and high-pressure coolant inj

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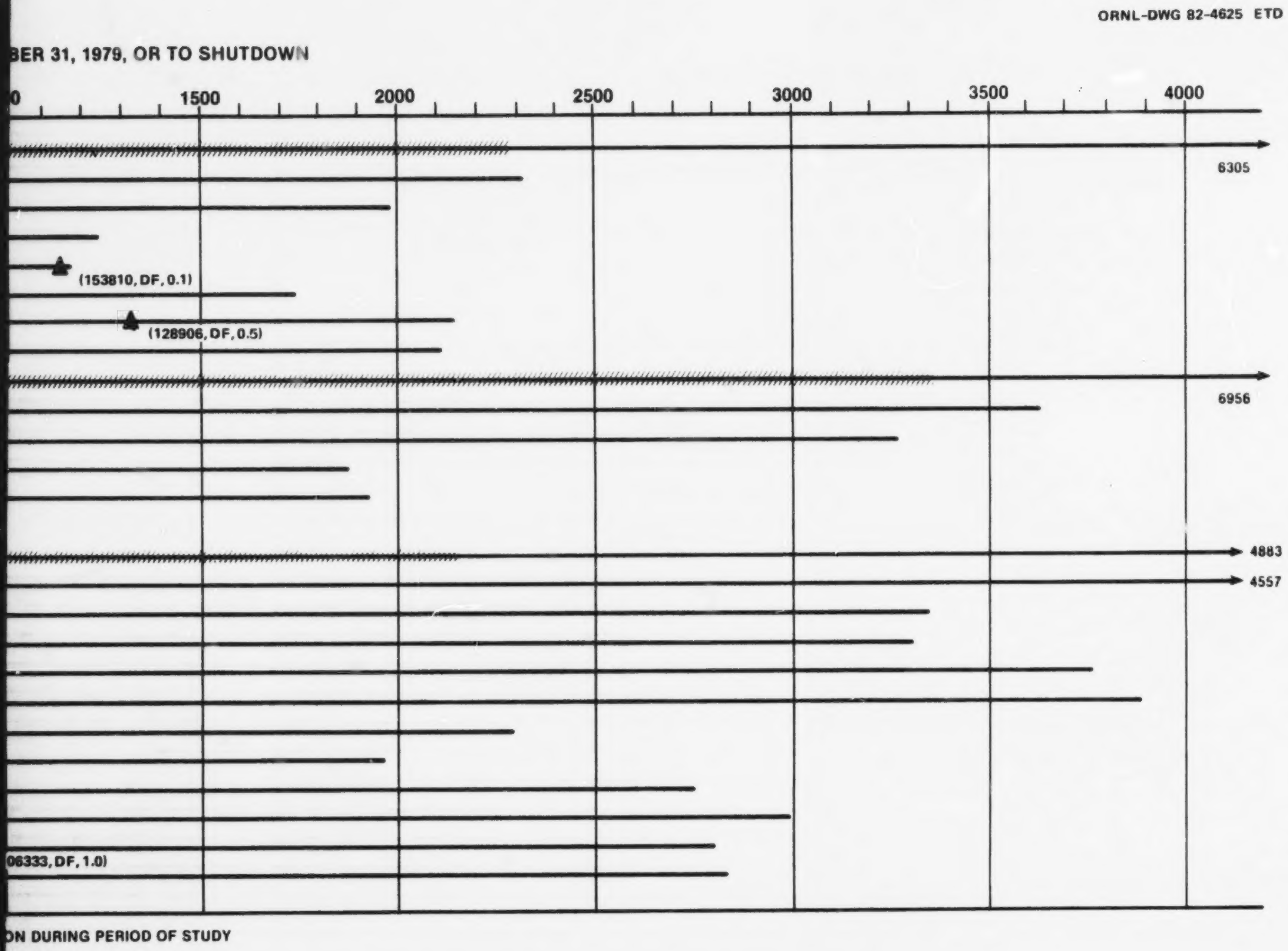

BWR failure of reactor core isolation cooling and high-pressure coolant injection.

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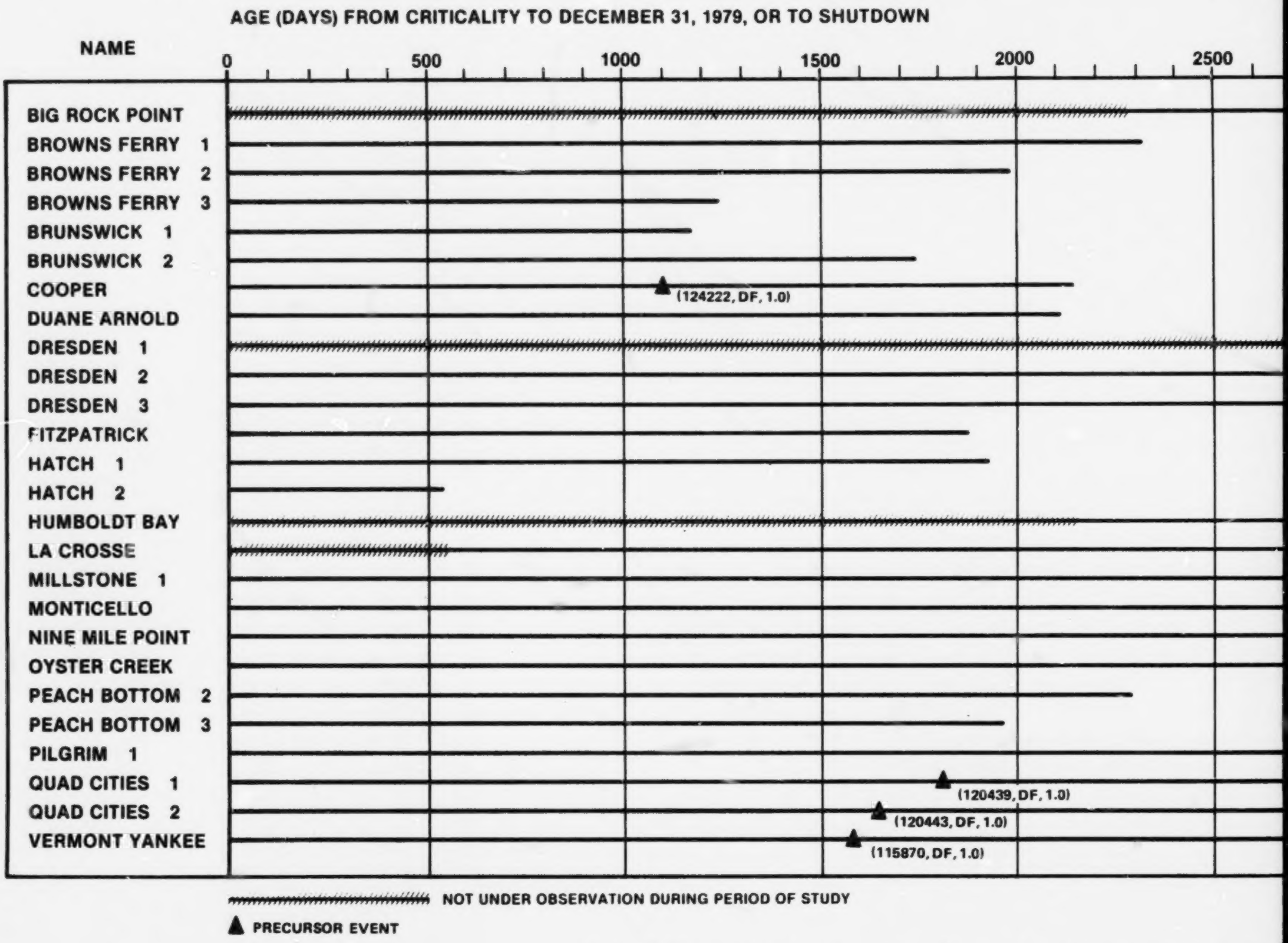

Fig. E.12. Time line for BWR failure of automatic depressurizat

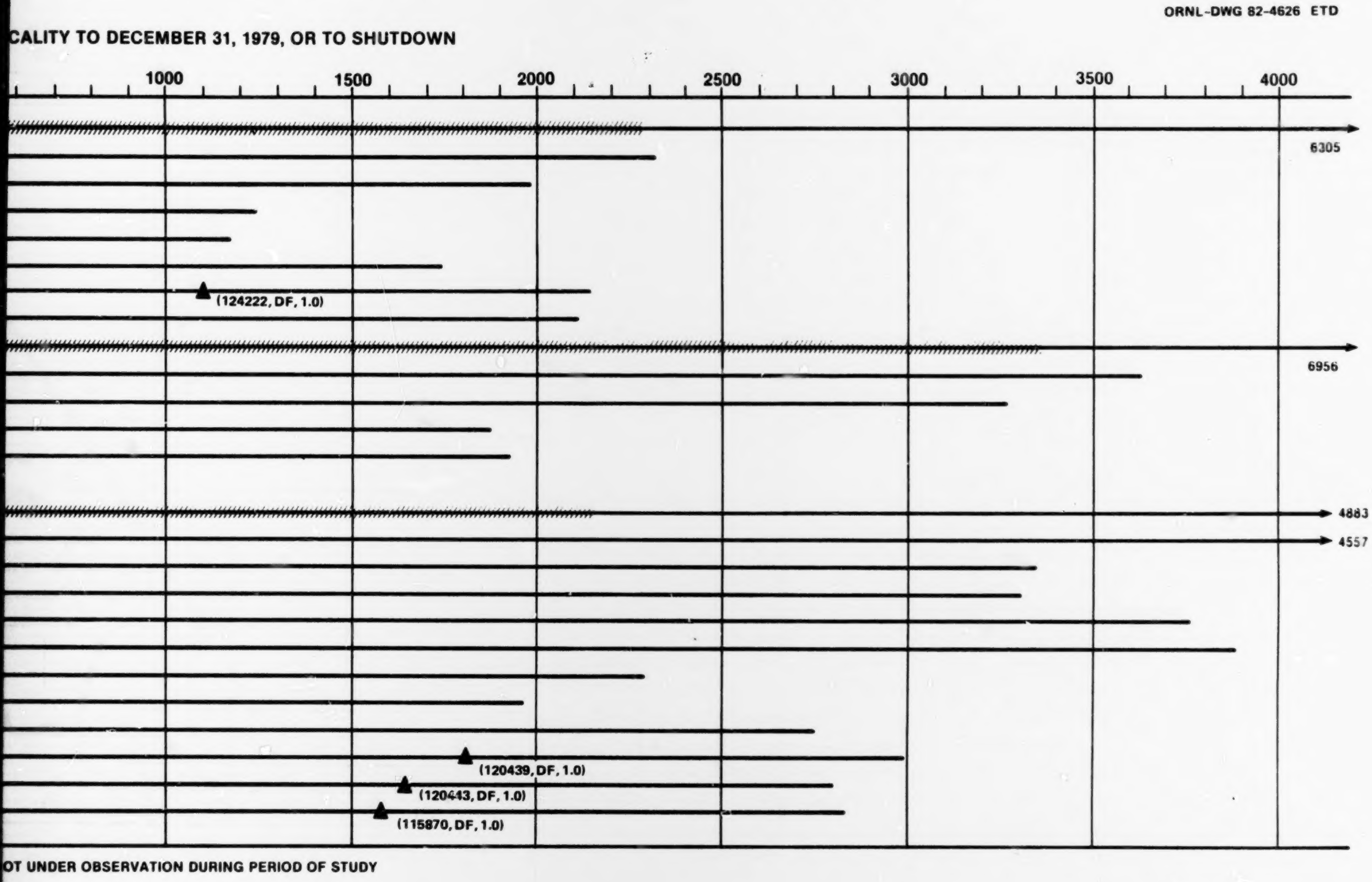

Fig. E.12. Time line for BWR failure of automatic depressurization.

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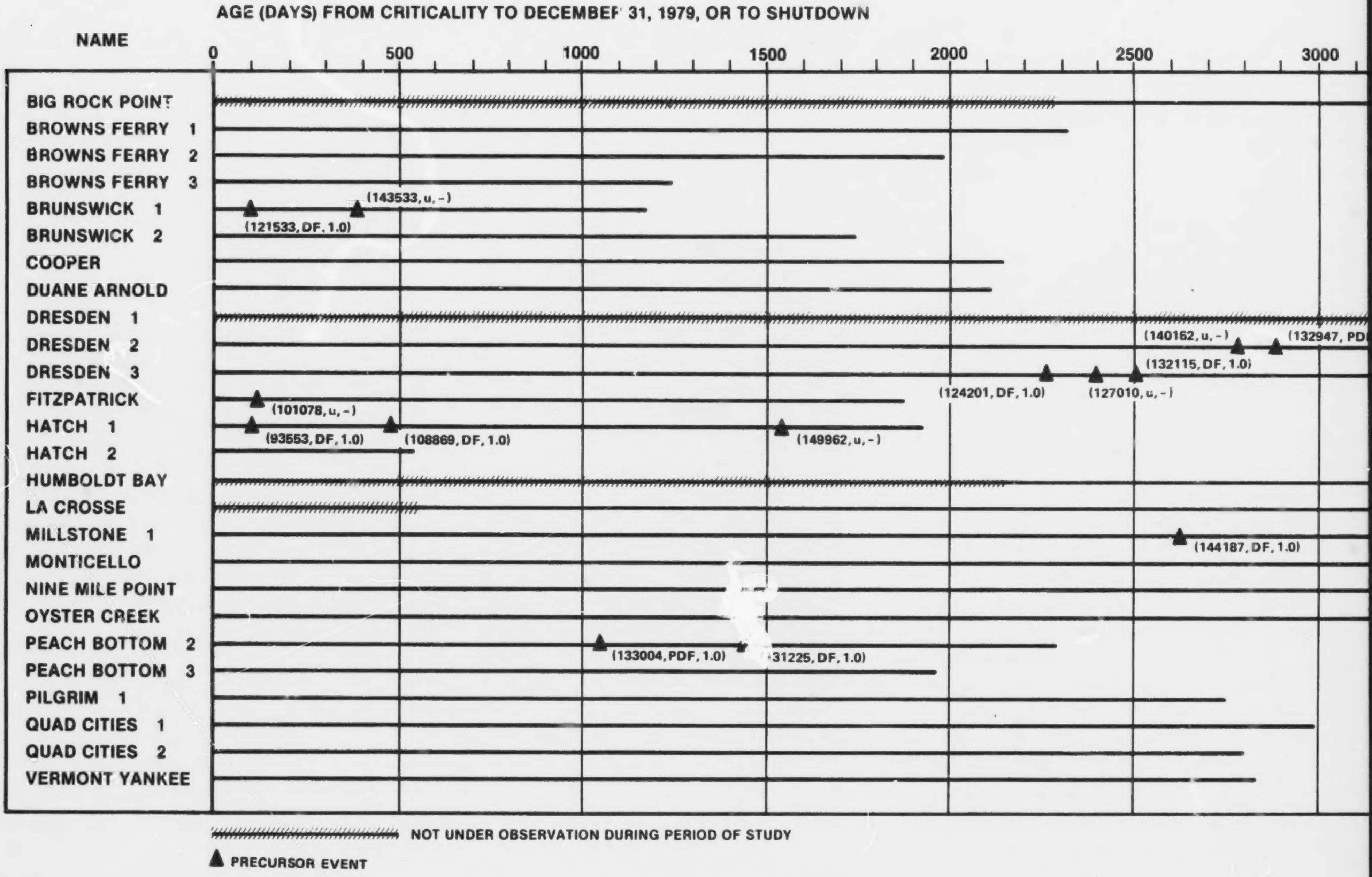

Fig. E.13. Time line for BWR failure of emergency power.

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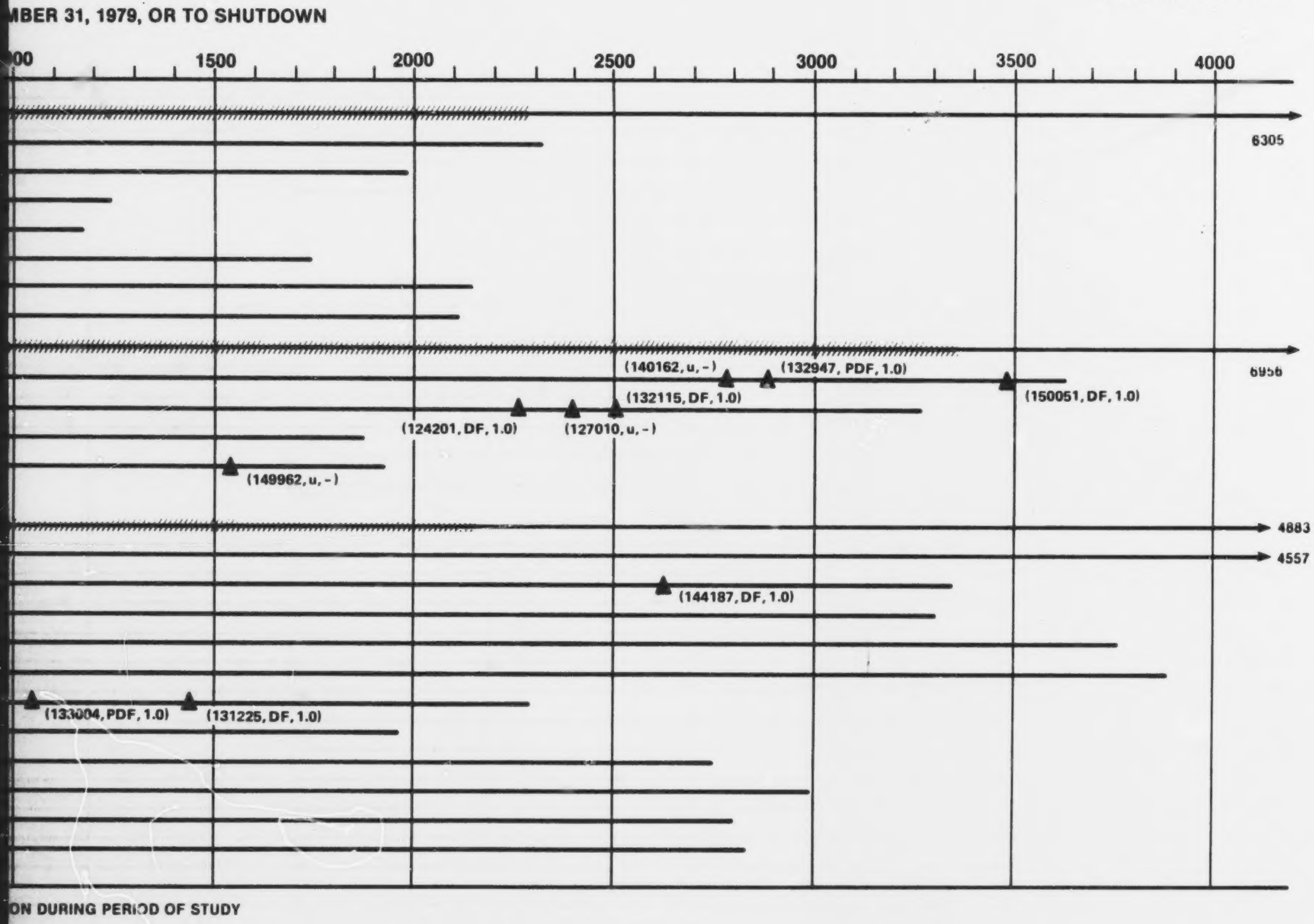

ig. E.13. Time line for BWR failure of emergency power.

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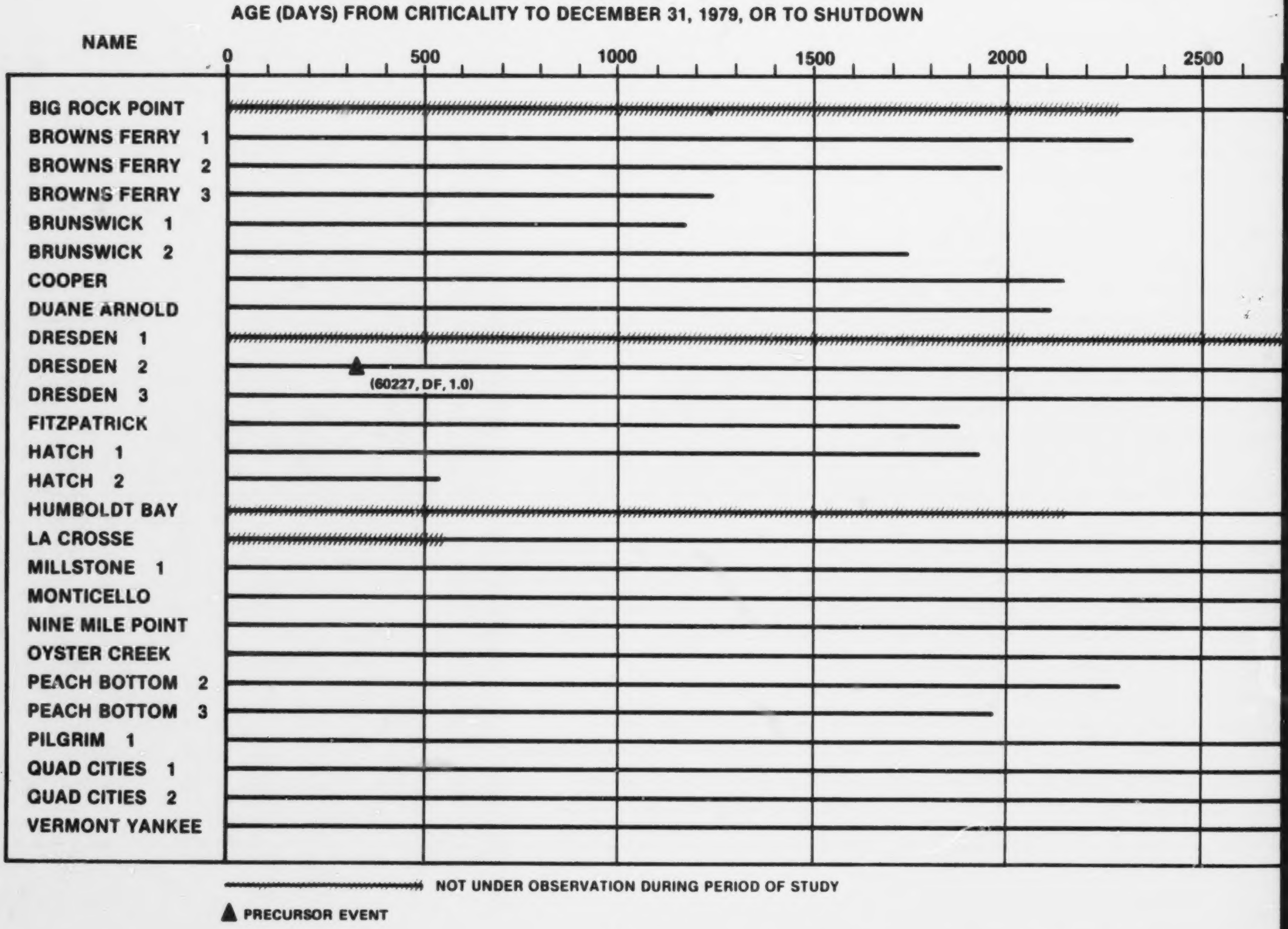

Fig. E.14. Time line for BWR failure of reactor vessel isolati

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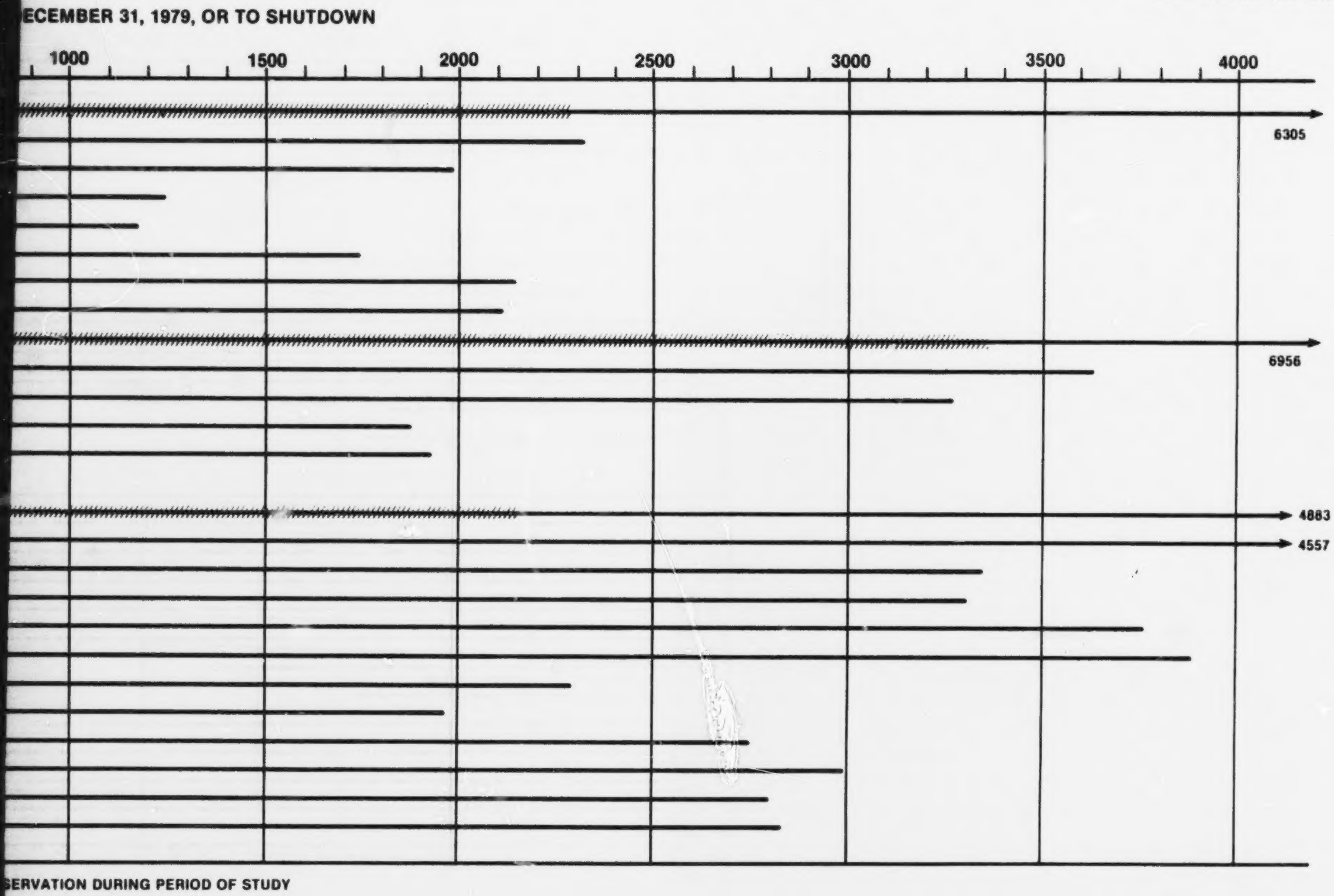

Fig. E.14. Time line for BWR failure of reactor vessel isolation.

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Table E.1. Degraded-function events that occurred within 1 month of reference plant and date combinations

Reference date and plant name	NSIC accession number	Event date	Description
April 30, 1970 Dresden 1	44752	April 30, 1970	Failure of the emergency condenser condensate valve was identified during startup operations checks. It did, however, operate manually. Apparently the valve had overheated. It was located in the primary steam-drum compartment where the temperature is above ambient.
	44751	April 27, 1970[a]	During routine testing three of four steam drum low level scram switches failed. They are float-type magnetrol devices. The sensor float chambers and switches were flushed after which they functioned satisfactorily.
October 30, 1972 Robinson 2	76461	November 5, 1972	During turbine valve testing, a fast load reduction from 520 MWe to 150 MWe and a subsequent manual reactor trip was effected due to testing difficulties. Secondary pressure relief valve RV-1 malfunctioned and stayed open for five minutes. During restart, relief valve RV-2 stuck open. Safety injection was later actuated and valve SI-867A did not open due to a maladjusted torque switch. RV-2 inner valve and guide bushing were badly scarred.
October 15, 1973 Peach Bottom 2	85584	October 31, 1973	Following the initial delivery of feedwater to the reactor vessel from the "B" reactor feedwater pump, the conductivity of the water increased from 0.3 to 34 $\mu\Omega$/cm. Crud levels also increased. The stagnant water in the piping was probably the cause. It was reduced below limits within 9 hours. During this period bellows failure indications were noted on two reactor relief valves. The insulation on the cables at the pressure switches associated with relief valves was also damaged. The cables were replaced with heat-resistant cables.
April 18, 1974 Dresden 2			None.
July 28, 1974 Cooper	94515	July 14, 1974	During capacity testing of the eight Target Rock relief valves, two valves failed to reclose properly. The failure was due to excessive steam leakage through the primary pilots.
	95391	August 19, 1974	An emergency diesel generator failed to automatically start when the startup transformer breaker was opened. The failure to autostart was caused by a disconnected wire in the junction box.

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[a] Letter date.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
September 9, 1974 Zion 2	95357	August 22, 1974	Due to operator error, the isolation valve for a steam generator relief valve was closed while the reactor was in the hot shutdown condition. The air supply to the relief valve was also found isolated.
	95327	August 25, 1974	The boric acid concentration in the boric acid storage tank was reduced to 83% of normal due to inadvertent stroking of the inlet valves while the tank was being recirculated. The inlet valves were also believed to be leaking.
	95326	August 29, 1974	Valve SI8803B, one of the two BIT inlet valves, failed to open automatically during an inadvertent safety injection. The valve was manually opened from the control room. No cause for the failure was found.
	95395	August 30, 1974	One MSIV failed to close during testing because the solenoid pilot operators could not open against excessively high hydraulic pressure which existed in the system due to a stuck pressure switch and an improperly set relief valve.
	96299	September 18, 1974	Diesel generator 2A tripped during starting. No cause for the failure could be found.
December 31, 1974 Duane Arnold	98952	December 22, 1974	During routine panel checks, the operator observed that the indicating lights for a HPCI-CST isolation valve were not functional. The 125-V dc control power to the valve had also been lost. The coil in an undervoltage sensing relay was open. No reason could be found for the coil failure.
February 3, 1975 Maine Yankee	99673	January 22, 1975	A pin-hole leak developed in the minimum flow recirculation line on the operating charging pump. The leak resulted from excessive erosion in the piping.
May 7, 1975 Hatch 1	102738	April 17, 1975	Following a scram a low level isolation was received. An outboard MSIV failed to close due to a stuck pilot solenoid.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
May 7, 1975 Hatch 1 (continued)	102739	April 25, 1975[a]	The RHR service water cross tie valve drive motor breaker tripped during testing, resulting in a failure of the valve to open. The breaker could not be reset because of a loose linkage set screw.
	103124	May 18, 1975	A MSIV failed to close upon demand using a control switch. A solenoid operated valve did not seat properly and prevented air from bleeding off the MSIV operating solenoid.
July 11, 1975 Robinson 2	104213	June 25, 1975	Boric acid transfer pump A failed at a keyway due to a broken shaft. The failure occurred while the pump was being used for BIT recirculation.
	104385	July 15, 1975	A discharge valve for the steam driven auxiliary feedwater pump failed to open during testing due to a faulty torque switch. The valve torque switch belleville spring was found filled with grease and the switch shaft was marred with a burr. Either of these defects were considered capable of changing the spring stiffness and preventing proper torque switch operation.
August 12, 1975 Brunswick 2	106361	August 12, 1975	A steam leak was noted around a globe valve stem during surveillance testing. The RCIC was taken out of service to repair the valve. This violated technical specifications.
	106443	August 14, 1975	The number 3 diesel generator was synchronized out of phase during surveillance testing resulting in the failure of the excitor diodes. The excitor was repaired; however, the diesel did not perform properly. A drain valve in the fuel line was cracked open allowing air to be sucked into the fuel supply line, thus starving the engine of fuel.
December 9, 1975 Oconee 2			None.
December 30, 1975 Pilgrim	109283	November 12, 1975	The "C" salt service water pump became inoperable. The line shaft bearing had worn out, causing the torque and pump shaft to bend. The pump was repaired and returned to service in 18 days.

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[a] Letter date.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
December 30, 1975 Pilgrim (continued)	109604	December 8, 1975	The "D" salt service water pump became inoperable. The shaft bearings were worn which caused the pump shaft to brake. The packing gland seal follower stud was also severed causing excessive leakage.
	110954	December 17, 1975	During testing of the "B" diesel generator, the turbo assist valves were not functioning properly. This resulted in a slow start time for the diesel.
	110291	December 24, 1975	The "A" salt service water pump was found to be inoperable. The shaft bearings were worn and the shaft had separated.
April 14, 1976 Dresden 2			None.
June 29, 1976 St. Lucie 1	115646	May 29, 1976	One of four redundant 120-V ac instrument power buses failed due to the failure of static inverter 1C. The inverter failed because of a failed oscillator circuit board.
	115937	June 17, 1976	The reactor experienced an overpressure transient (450–830 psia) during the initial stages of a heatup when the first reactor coolant pump was started. This occurred when 95°F RCS water was circulated through the steam generators, which caused a rapid heatup to 130°F.
	115936	June 26, 1976	A relief valve in a line associated with both boric acid makeup tanks developed an inlet-gasket leak, which resulted in both tanks draining below their specified minimum levels.
	117065	July 9, 1976	On two occasions, the turbine-driven AFW pump steam inlet valve failed to completely open because of moisture in the valve control circuit. After the second failure, the pump control circuitry was sealed.
	117491	July 18, 1976	During shutdown cooling, the RHR system suction relief valves did not properly seat, which resulted in the repeated reduction of pressurizer level and required on-and-off cycling of the shutdown cooling system. The valves were gagged to allow continuous shutdown cooling.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
August 23, 1976 Browns Ferry 3	116234	August 24, 1976	Startup testing on the HPCI turbine was being performed. The rupture disk located on the steam discharge line ruptured. The problem was traced to either binding of a swing check valve or a stop check valve in the exhaust line or both. Both check valves were repaired and HPCI was successfully tested.
	117957	August 26, 1976	Startup testing of the HPCI system was being performed. The HPCI turbine cycled between its overspeed trip and the trip reset and restart point. The turbine governor box was incorrectly grounded.
	118739	September 21, 1976	During HPCI testing, the HPCI shaft oil pump would not maintain pressure, which resulted in erratic operation of HPCI. This also caused the oil pump to cycle on and off. The problem was traced to a loose union on the suction side of the oil pump, which permitted the pump to suck air and resulted in reduced pressure.
	118740	September 23, 1976	A cable was found open in the RHR logic during testing. This prevented the 3C RHR pump from starting on normal ac power. The pump would have initiated on emergency ac power.
November 2, 1976 Surry 1	119769	October 18, 1976	Condenser outlet valve MOV-CW-100A failed to close during a test due to a loose cable terminal screw.
	119727	November 1, 1976	A power capacitor for comparator TC-1-432C failed, which resulted in a failure of the comparator to trip. The comparator provides overtemperature rod stop and overtemperature reactor trip signal.
December 13, 1976 FitzPatrick	120552	November 17, 1976	The "B" emergency diesel generator failed to start during testing. The converter inside the generator tachometer relay was found to be defective.
	120202	November 19, 1976	Relief valve 02-RV-71F inadvertently opened while the reactor was at power and began discharging into the torus. Monitoring relief temperatures failed to indicate the stuck open relief since the thermocouple also failed. All 4 RHR pumps were started and operated in the torus cooling mode. The reactor was scrammed when the relief valve could not be reclosed. No cause for the relief valve failure could be identified.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
December 13, 1976 **FitzPatrick** (continued)	120496	November 19, 1976	An automatic transfer of the HPCI suction from the CST to the torus was initiated. A torque overload caused the motor to fail and the valve had to be manually opened.
	120466	December 6, 1976[a]	With the reactor at power, a relief valve inadvertently actuated resulting in a cooldown rate of greater than 100°F.
	121294	December 15, 1976	The "A" emergency diesel generator failed to start due to low lube oil pressure during a test. Apparently the soak-back pump was putting out insufficient pressure.
January 17, 1977 **Palisades**	122430	February 5, 1977	Heater H68A for boric acid tank T-53A was discovered leaking.
	122939	February 11, 1977	During testing, a nipple in a line to a pressure switch in the jacket cooling water system began leaking. This leakage caused one of the air start motors to cycle between start and stop, which depleted the starting motor's air supply.
April 8, 1977 **Brunswick 2**	124230	March 23, 1977	HPCI isolated on high differential temperature while the reactor was at power. The temperature differential between the HPCI room and the supply air exceed the isolation set point.
	124913	April 5, 1977	The reactor had just scrammed from 70% power. HPCI auto started but tripped, apparently due to high differential temperature isolation. The reactor building heating was off due to the auxiliary boilers being secured. A high temperature difference resulted between the warm HPCI room and the cold reactor building makeup air. RCIC was used to maintain vessel level.
	124912	April 9, 1977	The "2B" nuclear service water pump failed to start several hours after being returned to service following preventive maintenance checks. An inspection revealed that the closing spring charging motor fuses were not making good electrical contact.

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[a] Letter date.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
April 8, 1977 Brunswick (continued)	125149	May 7, 1977	The reactor scrammed on low water level due to a loss of feedwater. The RCIC was manually initiated but tripped on overspeed. HPCI was used to maintain reactor vessel water level. The control operator did not ensure that the manual speed setting on the RCIC flow controller was set at the minimum prior to manual initiation.
April 25, 1977 Crystal River 3	124919	April 15, 1977	Makeup system containment isolation valve MUV-258 failed to close due to dirty control contacts. Chemical addition system containment isolation valve CAV-2 failed to close because of a weak closure spring.
	124918	April 16, 1977	Turbine-driven emergency feedwater pump tripped on overspeed due to slow response of the governor (reason for governor slow response not specified).
	124920	April 16, 1977	An out-of-calibration pressure transmitter prevented the complete closure of startup feedwater valves FWV-39 and FWV-40. This caused a steam generator overfill and a 101°F cooldown in 20 minutes.
	125093	April 21, 1977	Both boric acid tank suction valves (CAV-38 and CAV-46) were found shut. The cause of the valves being shut was not determined.
August 2, 1977 Monticello	128896	August 5, 1977	During a test, a resistor in the HPCI governor control system failed resulting in a loss of dc supply power to the system.
	129779	August 28, 1977	The "B" RHR injection valve failed to open during a test. The motor control center contactor did not close as required when the valve open signal was received. The control wire voltage drop during an open signal prevented the slightly worn contactor from closing.
August 3, 1977 Hatch 1	127933	July 27, 1977	The RCIC turbine tripped during testing and the throttling valve would not actuate to reset the RCIC turbine. A Barton 288A-17241 switch had dirty contacts.
	128083	August 9, 1977	While performing a scram recovery, the 1C safety relief valve failed to open in the presence of high reactor pressure. The other 10 safety relief valves were available.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
August 3, 1977 Hatch 1 (continued)	128613	August 12, 1977	The operator was unable to adjust the output voltage of the 1A diesel generator using the manual regulator control. Two diodes in the regulator's power supply had failed. (The diesel generator does not use the manual regulator during auto-initiation.)
	129630	August 18, 1977	The 1B diesel generator overheated during testing and was manually shut down. The overheating caused the inboard bearing to fail. The cause of the overheating could not be determined.
September 8, 1977 Cook 1	130111	September 1, 1977	A loss of offsite power occurred due to a lightning-induced 5 cycle, 64% voltage dip, which prematurely tripped the reactor, combined with the unavailability of the normal reserve auxiliary power caused by a previous lightning strike. The diesel generators started and provided power to safety-related loads. A manually loadable auxiliary reserve offsite power source was available.
	130892	October 7, 1977	West component cooling water outlet isolation valve CMO-420 failed to operate remotely due to internal binding.
April 8, 1978 FitzPatrick	137936	April 6, 1978	The RHR shutdown cooling inboard isolation valve, 10MOV18, motor control power fuse blew resulting in the valve being inoperable in the closed position. The controller auxiliary contacts had failed causing the fuse to blow.
	137937	April 8, 1978	A HPCI pump operability test was being performed when the motor operator separated from the body of valve 23 MOV 14. The fasteners which attach the adapter plate to the yoke failed.
	138275	April 10, 1978	Speed control of RCIC turbine was lost during surveillance testing. Dirty contacts on the limit switch of 13 MOV 131 caused the failure.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
April 8, 1978 FitzPatrick (continued)	138336	April 24, 1978	Following a scram and isolation, reactor water level was controlled by venting steam to the main condenser since the reactor water cleanup (RWCU) system was inoperable. This resulted in an excessive cooldown rate. The RWCU isolation valve, 12 MOV 15, was inoperable. Its motor was burned out and the gear in the manual operator was broken.
	138351	April 29, 1978	During a reactor startup, the HPCI isolation valve, 23 MOV 15, would not open. The torque switch associated with the open valve circuit was out of adjustment.
April 17, 1978 Cook 2	137520	March 18, 1978	Check valve 2-FW138-1 stuck open during use of the AFW system to maintain steam generator level. This resulted in back-flow from steam generator number 1 to the AFW system. The cause of the valve sticking open was not determined. Reverse flow was stopped by manual closure of valve 2-FMO-211.
	137544	March 19, 1978	Air starting check valve for diesel generator 2CD, cylinder 5, rear bank fractured and broke in two places. This resulted in blown out gaskets in the air start line.
	137546	March 24, 1978	Steam generator 4 channels 1 and 2 feed flow transmitters and impulse lines were discovered air bound.
	138273	March 25, 1978	While conducting turbine stop and control tests on control valve D, control valve A opened excessively because of a loose cap nut on an adjusting screw. The reactor tripped on low-low steam generator level.
	137908	April 1, 1978	During startup, reactor coolant loop 1 overtemperature ΔT module failed (cause unspecified).
	137910	April 16, 1978	During ECCS operability testing, the chain-operated handwheel for RH-104W, the west RHR pump manual isolation vavle, came off the valve stem while the valve was in mid-position instead of fully open. This resulted in an inoperable train. The valve could have been opened by using a wrench or by holding the handwheel on the shaft.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
April 17, 1978 Cook 2 (continued)	138931	April 22, 1978	Component cooling system valve CMO 414 failed to operate correctly due to worn switch contacts.
	139377	May 11, 1978	Turbine stop valve D closure limit switch became inoperable on two occasions (reason unspecified).
August 19, 1978 Calvert Cliffs 2	140349	August 1, 1978	Diesel generator 21 tripped during testing on high jacket cooling water temperature when its service water supply valve failed to open. The supply valve failed to open due to a worn plunger seat which caused the solenoid to stick.
	141069	August 1, 1978	A 1-gpm leak was discovered in the common suction line to the charging pumps. The leak occurred due to a crack in the heat-affected zone of a previous weld.
October 14, 1978 Crystal River 3	141512	October 4, 1978	During ECCS pump operability tests, decay heat control valve DHV-110 would not control at the proper flow due to the fact that flow controller DH-43-FIS was not valved in.
	141398	October 14, 1978	Makeup pump MUP-3C lube oil backup pump lost indication and failed to start because of two blown fuses in the indication and control circuitry. No cause was specified for the blown fuses.
	141821	October 30, 1978	Both concentrated boric acid tank outlet valves (CAV-38 and CAV-43) were found shut. The cause was the failure to open the valves following tank recirculation.
November 30, 1978 Oyster Creek	142776	November 30, 1978	During an auto actuation test, the number one diesel generator started but failed to excite and pick up load. Also during the test the number one service water pump tripped on undervoltage and failed to reset. The number 2 service water pump also failed to reset after tripping during a test of the number 2 diesel. However, both service water pumps started when the generator breaker was closed. Failure of the number one diesel generator was caused by failure of mechanical linkage. The problem with the service water pumps was attributed to binding of the trip mechanism.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
December 5, 1978 Robinson 2	142378	November 9, 1978	Instrument air supplies to RHR flow control valves RHR-605 and RHR-758 were discovered not to be isolated (as required by Technical Specifications) due to a procedural deficiency.
	142775	November 28, 1978	RPS relay RT-3B failed due to the thermal deterioration of an epoxy adhesive which caused the relay to stick in the energized position.
	146521	December 17, 1978	MSIV C failed to operate during testing due to a maladjusted stem packing gland.
January 3, 1979	146557	December 30, 1978	Component cooling water heater exchanger outlet valve SW-1424 failed to open (no cause found). Subsequent improper control operation resulted in discovery of a misaligned and slipping valve to operator linkage.
	146690	January 2, 1979	Main steam valves MS106 and MS106A to AFW pump 1-1 failed to open because of a buildup of dirt on the valve stems caused by construction activity in the area.
	148614	January 3, 1979	Low recirculation flow on HPI pump 1-1 due to inability of recirculation line heat tracing to maintain line temperature above freezing.
	146693	January 6, 1979	During surveillance testing, decay heat valves DH9A opened and DH7A closed when a BWST level bistable was tripped due to failure of output relay K51A in SFAS channel 4.
	146744	January 12, 1979	As a result of an accidental grounding of a containment hydrogen analyzer and the incorrect installation of a standard fuse in the analyzer, the 125-V dc fuse to inverter Y2 blew. This resulted in a loss of power on bus Y2 and a consequent loss of power to RPS, SFAS, and SFRCS channel 2. This caused a false ICS signal resulting in rapid reduction in feed flow and rapid increase in reactor power and subsequent reactor and full SFRCS trip.
	147248	January 15, 1979	Reactor coolant pump 1-2-2 was started with incorrect breaker alignment which caused low voltage relays to trip and de-energize both 4.16-kV essential buses C1 and D1. Both emergency diesel generators started and supplied essential loads.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
January 3, 1979 Davis-Besse 1 (continued)	148320	January 16, 1979	A 1/2-in. nipple at discharge of gear driven lube oil pump for makeup pump 1-1 failed due to fatigue failure due to vibration.
	148318	January 17, 1979	Core flood tank 1-2 isolation valve CF1A failed to close remotely because of a loose set screw which caused a cracked pinion gear in the valve motor operator.
	148315	January 30, 1979	Main steam code safety valves SP17A2 and SP17B2 lifted below their set point range during load swings. Valve SP17A2 was found to have a loose spindle and was gagged. Valve SP17B2 was tested, found satisfactory, and was returned to service.
January 26, 1979 Dresden 2	146498	January 3, 1979	The HPCI turbine failed to start during the quarterly flow test. The interlock dump valve operating lever was out of adjustment.
	148322	February 23, 1979	The swing diesel was manually started prior to taking the number 32 transformer out of service. About 15 minutes later the cooling water pump tripped on thermal overload. It was reset but tripped again after 20 minutes. The redundant power supply was also found tripped. No cause could be found for the trips.
March 15, 1979 Oconee 1	148807	March 15, 1979, March 25, 1979	On both dates HPSW pump B was removed from service in order to repair leakage at the joint connecting the pump motor cooler to its supply line.
May 30, 1979 Browns Ferry 2	150245	May 28, 1979	While conducting postrefueling startup testing of the RCIC turbine, the electronic overspeed device could not be reset. Corrective action was not discussed. HPCI was operable.
	150244	May 30, 1979	The RCIC tripped on overspeed due to failure of the governor actuator and the turbine shaft bearings.
May 31, 1979 Prairie Island 1	150416	June 9, 1979	During a cooldown, PORV isolation valve MV-32196 failed to close due to the failure of a torque switch.
	150417	June 11, 1979	Steam generator level channel 1LT471 responded slowly to level changes due to a defective transmitter diaphragm assembly.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
September 6, 1979 FitzPatrick	151866	September 4, 1979	A leaking cell was noted in station battery "B". The cell was intentionally jumped until a replacement could be obtained. Jumping the cell caused the battery to be unavailable.
	152011	September 6, 1979	A test of the HPCI subsystem logic was being performed whe the motor on the condensate storate tank suction valve failed. Because of inadequate communications between plant management and operations personnel, the torus suction valve was rendered inoperable.
September 10, 1979 Salem 1	151947	September 7, 1979	During 18 month safeguards system surveillance, several safeguards systems could not be reset due to the tripping of 28-V dc control power breakers. The breakers tripped because the circuit loads were approximately 2 A, while the breakers were rated at 1 A.
September 17, 1979 Browns Ferry 1	152470	September 26, 1979	Both the A and the B recirculation pumps tripped while troubleshooting the MSL temperature relays. The operator checked the wrong terminals in the auxiliary instrument room. The reactor load fell from 98% power to 35% power. The recirculation pumps were returned to service in 28 minutes.
	152934	October 10, 1979	While surveillance testing was being performed on HPCI, the rupture disk failed. The teflon sheet portion of the disk failed providing no protection to the disk under vacuum conditions.
	153645	October 17, 1979	While performing surveillance testing of the HPCI, flow control valve FCV 73-27 would not open. Dirty contacts on the valve's limitorque operator limit switches prevented valve operation.
September 17, 1979 Davis-Besse 1	152335	August 27, 1979	Auxiliary feed pump 1-2 steam inlet valve MS 107 failed to open during testing (cause undetermined).
	152336	September 1, 1979	Level transmitter LT-SP9A7 to SFRCS channel 3 failed due to a faulty input buffer card caused by a failed optical isolator. This resulted in a steam generator No. 2 low level trip on SFRCS channel 3.
	152337	September 8, 1979	Source range neutron detector NI-1 and intermediate range neutron detector NI-3 failed low due to corrosion of signal return cable connectors.

Table E.1 (continued)

Reference date and plant name	NSIC accession number	Event date	Description
September 17, 1979 Davis-Besse 1 (continued)	153320	September 17, 1979	Inoperable optical isolator on relay drive board of SFRCS channel 3.
	152950	September 25, 1979	AFW pump turbine inlet valve MS106 lost indication due to a loose lamp retainer ring which grounded and blew the control power fuse. Cross-connect valve MS106A was also found not operating (reason unspecified).
	152952	October 4, 1979	SFRCS channel 4 ±15 V dc power supply failed, resulting in a SFRCS channel 2/4 half-trip (reason unspecified).
	152953	October 4, 1979	Decay heat cooler 1 component cooling water outlet valve CC1467 failed to operate due to slippage of valve linkage caused by loose retaining bolts. The linkage bolts loosened because of vibration.
	152951	October 15, 1979	An ICS capacitor shorted to ground, which resulted in a unit trip from 69% power. While later reclosing the generator output breaker, the 345 kV "J" bus breaker tripped because parts of a damaged breaker muffler caused a fault to ground when the breaker was reclosed. This resulted in a loss of offsite power. Both emergency generators started and supplied power to safety-related loads.

Table E.2. Degraded-function events that occurred within 1 month of significant precursors

Significant precursor date and plant	NSIC accession number	Event date	Description
July 15, 1969 Haddam Neck	36147[a]	July 15, 1969	Loss of offsite power due to incorrect switching orders. Diesel 1C was slow in starting. Charging pump 1C tripped on thermal overload due to full flow demand at the time of starting. Seals on reactor coolant pump 4 failed.
	39046	August 2, 1969	A plant shutdown was initiated due to a near-plant lightning strike which resulted in fault signals that opened the two plant output breakers.
November 27, 1970 Humboldt Bay	61434[a]	November 27, 1970	A loss of offsite power resulted from grid disturbances during a severe storm. The emergency generator started and assumed loads.
	58506	December 2, 1970	The plant operated with less than normal power sources for more than 12 hours. One transmission line was out of service and a break occurred in the other. Both fossil units at the station operated normally.
January 12, 1971 Point Beach 1	59484[a]	January 12, 1971	Inoperability of the two sump isolation valves from the control room due to two solenoid valve failures in the valve hydraulic oil system.
	65757	February 5, 1971	Loss of offsite power due to breaker opening on the three high lines during an ice storm.
February 5, 1971 Point Beach 1	59484	January 12, 1971	Inoperability of the two sump isolation valves from the control room due to two solenoid valve failures in the valve hydraulic oil system.
	65757[a]	February 5, 1971	Loss of offsite power due to breaker opening on the three high lines during an ice storm.
March 8, 1971 Robinson 2	63144[a]	March 8, 1971	Both diesel generators failed to run after new low oil pressure switches were remounted on a wall 15 feet from the diesels. The failure to run was traced to the cold and viscous oil and some entrained air in the 1/4-in. line which prevented pressure buildup within the time limit.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
March 8, 1971 Robinson 2 (continued)	63121	March 14, 1971	Failure of lubrication oil supply to the turbine and generator bearings due to inadvertent reduction in battery voltage caused by the continued operation of the dc emergency oil pump following a pump test.
March 29, 1971 LaCrosse	62329	March 12, 1971	After installing an accumulator in the A1 seal injection pump, the injection system began to operate erratically, causing the circulating pumps to trip and the reactor to trip. The "1A" pump had not been completely vented which resulted in the "1B" pump becoming air bound.
	63129[a]	March 24, 1971	Failure of a potential transformer in the switchyard caused a fire, loss of power to the reactor, a load rejection, and a scram. The shutdown condenser was used for reactor temperature and pressure control. Power was restored in 61 minutes.
	62331	March 24, 1971[b]	During an approach to power, level, flow, and pressure oscillation were encountered which finally resulted in a reactor trip. The problem was traced to the feedwater pump automatic controls. They were unstable at low flow. Procedures were changed to manually control feedwater at low flows.
September 2, 1971 Palisades	65960	August 19, 1971	With the reactor shutdown, a 1/4 gpm leak was detected in a reactor coolant pump mechanical seal unit. The leak resulted from a 3/8-in.-long crack caused by metal fatigue due to improper support of a 3/4-in. schedule 80 pipe.
	61565[a]	September 2, 1971	Loss of offsite power due to the trip of one line and inadvertent tripping of two breakers caused by a faulty breaker failure relay. Both diesel generators started but diesel generator 1-2 failed to close in on the dead bus until the operator turned the synchoscope plug in preparation for closing the breaker manually.

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[a] Significant precursor.

[b] Letter date.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
September 2, 1971 Palisades (continued)	65969	September 8, 1971	A technician de-energized the breakers to the reactor protection system to make a minor modification. This resulted in the inadvertent opening of the electromatic relief valves. The RCS blew down to 1280 psia over a period of 2–3 minutes until the motor operated relief valve isolation valves were closed. The failure was a result, in part, of the use of nonstandard contact designation in the PORV control circuits.
	66531	September 15, 1971	Two control rods failed to drop during low power physics testing due to the intrusion of epoxy and other materials into the drive mechanism. Too much epoxy had been used during installation of new springs and pins on the magnetic clutches.
October 10, 1971 Millstone 1		September 17, 1971	While performing surveillance testing on LPCI and core spray motor operated valves, the LPCI-1-LP-10B injection valve and the 1-LP-13A torus spray valve failed to operate. Their motors were burned out. The motors were replaced with larger motors and the valves functioned properly.
	66996[a]	October 10, 1971	A malfunction in the turbine control system resulted in the blowdown of over 75,000 gallons of water. A relief valve opened and failed to reset. Insulation had been placed around the pilot which caused the set spring to anneal, thus changing the set point.
		November 2, 1971	During testing the gas turbine would not ignite. The failure was traced to a faulty solder connection in the speed switch which caused the turbine to trip prior to ignition.
	58005	November 8, 1971	The gas turbine tripped during a test when the dc lube oil pump did not reach rated pressure. Adjustments were made to increase the pump motor speed and the lube oil sump temperature was increased to 80°F.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
October 10, 1971 Millstone 1 (continued)	60817	December 4, 1971[b]	During a test the gas turbine generator would not accept its load. The electric generator dc emergency lube oil pump did not reach the required pressure in time to prevent a turbine trip. Two additional heaters were installed in the sump.
June 18, 1973 Turkey Point 4	81523[a]	June 18, 1973	During initial turbine synchronization with the transmission system, the turbine control valves opened rapidly and excessively, which resulted in a decrease in RCS temperature, a reactor trip, and safety injection initiation. The auxiliary feedwater pumps did not start automatically because the 125 V dc control power fuses for the auto-start logic circuit had not been installed.
	82677	July 13, 1973	Two intake cooling water pumps were disabled due to a short between the No. 4 startup transformer and the No. 4B 4160 V bus.
October 21, 1973 Ginna	85370[a]	October 21, 1973	A loss of the offsite power occurred due to transmission line instability. The addition of cold water resulted in a 85°F drop in cold leg temperature in 10 minutes. Safety injection was initiated and SI pump suction was transferred from the BASTS to the RWST prematurely because of a loss of power on instrument bus 1A which resulted in the generation of a false signal.
November 19, 1973 Browns Ferry 1 (NSIC 85566)	85750	November 14, 1973	While testing a newly installed 1/4 amp switch in the HPCI inverter, the inverter fuse failed twice. Voltage spikes were experienced when contacts in related instrumentation were opened. A spike suppressor was placed across the coil of the relay which greatly reduced the spike. Further fuse failures did not occur.
	85566	November 19, 1973[b]	While preparing for a loss of offsite power test, the 4-kV unit boards were placed in manual to prevent auto transfer. The turbine began to vibrate resulting in a manual turbine trip and subsequent reactor scram. Neither HPCI or RCIC could be initiated until the diesel generators were energized since the breaker resets required ac power. A design change was instituted to eliminate the ac power dependence of HPCI and RCIC.

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[a] Significant precursor.

[b] Letter date.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
November 19, 1973 Browns Ferry 1 (NSIC 85566) (continued)	85738[a]	November 19, 1973[b]	The RCIC system failed to operate following a 25% loss of offsite power test. HPCI was initiated, it tripped but was immediately reset and controlled reactor vessel water level. The RCIC steam inlet valve failed to open because its electrical contactor hung up on the arc suppressor.
	87241	December 19, 1973	During a test the "A" diesel generator did not supply adequate voltage to the 2A RHR pump, thus the pump could not start. The diesel generator's voltage regulator had failed. It was replaced and the diesel generator performed properly.
November 19, 1973 Browns Ferry 1 (NSIC 85738)	85750	November 14, 1973	While testing a newly installed 1/4 amp switch in the HPCI inverter, the inverter fuse failed twice. Voltage spikes were experienced when contacts in related instrumentation were opened. A spike suppressor was placed across the coil of the relay which greatly reduced the spike. Further fuse failures did not occur.
	85566[a]	November 19, 1973[b]	While preparing for a loss of offsite power test, the 4 kV unit boards were placed in manual to prevent auto transfer. The turbine began to vibrate resulting in a manual turbine trip and subsequent reactor scram. Neither HPCI or RCIC could be initiated until the diesel generators were energized since the breaker resets required ac power. A design change was instituted to eliminate the ac power dependence of HPCI and RCIC.
	85738	November 19, 1973[b]	The RCIC system failed to operate following a 25% loss of offsite power test. HPCI was initiated and tripped but was immediately reset and controlled reactor vessel water level. The RCIC steam inlet valve failed to open because its electrical contactor hung up on the arc suppressor.

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[a] Significant precursor.

[b] Letter date.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
November 19, 1973 Browns Ferry (NSIC 85738) (continued)	87241	December 19, 1973	During a test the "A" diesel generator did not supply adequate voltage to the 2A RHR pump, thus the pump could not start. The diesel generator's voltage regulator had failed. It was replaced and the diesel generator performed properly.
November 30, 1973 Surry 1	89205[a]	November 30, 1973	Failure of reactor coolant pump A shaft.
	89206	November 30, 1973	Failure of reactor coolant loop B isolation valve shaft during cooldown in conjunction with reactor coolant pump A shaft failure.
January 19, 1974 Haddam Neck	88084	January 18, 1974	Due to low temperatures and failed heaters, sensing lines for Nos. 1 and 2 main steam line excessive flow instrumentation froze, resulting in an apparent high steam flow condition and subsequent reactor scram.
	88451[a]	January 19, 1974	A total loss of offsite power occurred during an ice storm due to a momentary fault in one line and a subsequent inadvertent trip on the other due to improper blocking relay placement. Both diesel generators started, but one diesel service water pump had to be manually started due to a malfunction in the time delay undervoltage relay in the pump motor start circuit.
April 7, 1974 Point Beach 1	90445	April 4, 1974	One of two steam generator sample line isolation valves failed to close on a radiation signal due to the failure of its solenoid valve. No cause for the failure was found.
	90421[a]	April 7, 1974	Plugged suction strainers were found in the inlets to all three auxiliary feedwater pumps during a plant cooldown.
May 8, 1974 Turkey Point 3	93702	April 25, 1974	When the Unit 4 startup transformer lockout relay was reset while the transformer was isolated for testing and maintenance, current flowed through a sneak circuit and energized Unit 4 generator protection relays. This opened the generator breakers on both Units 3 and 4. Both reactors tripped automatically. A Unit 4 safety valve lifted and did not reseat until the manual lifting device was removed.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
May 8, 1974 Turkey Point 3 (continued)	91115	May 3, 1974	A safety injection pump was started to add water to the SI accumulators. Low discharge pressure resulted from air entrapped in the pump casing. Inadequate venting had been performed after recent system maintenance.
	91676[a]	May 8, 1974	Three auxiliary feed pumps failed to start during testing. Two of the three pumps had overtightened packings and the third had a sticking governor linkage.
	92449	May 30, 1974[b]	The turbine stop valves failed to close during a normal shutdown due to phosphate buildup between the valve shafts and bushings.
March 22, 1975 Browns Ferry 1	100362	February 26, 1975	During startup following a trip, a main steam relief valve lifted prematurely and did not reset until the reactor had depressurized to 480 psig. The valve had been manually actuated immediately following the trip. It and another valve of questionable behavior were replaced.
	101444[a]	March 22, 1975	A fire in the cable spreading room caused extensive damage at the Browns Ferry 1 reactor.
	102267	April 16, 1975	An LPCI injection valve failed to operate electrically during testing. The bolts securing the drive motor to the valve became loose and finally failed.
April 29, 1975 Brunswick 2	102613	April 4, 1975	The conductivity of the condenser hotwell was increasing. An attempt was made to isolate the problem; however, the reactor scrammed from 11% power. The feed pump was restarted to maintain the reactor water level. The cooldown rate exceeded 100°F/h.
	103141	April 6, 1975	While operating at 9% power in the startup mode the B safety relief valve opened and failed to reset. The cooldown rate exceeded 100°F/h. It is believed a momentary ground caused the valve to stick open.

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[a] Significant precursor.

[b] Letter date.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
April 29, 1975 Brunswick 2 (continued)	103002[a]	April 29, 1975	While operating at 10% power a relief valve opened and could not be closed. It is believed the pilot was leaking excessively. The operator failed to manually scram the reactor as per operating procedures. The reactor subsequently automatically scrammed. An attempt to place the RHR B loop in service also failed. The service water supply valve motor contacts were dirty. The cooldown rate exceeded 100°F/h.
May 1, 1975 Robinson 2	103077[a]	May 1, 1975	Failure of reactor coolant pump C seal.
	103199	May 21, 1975	Failure of boric acid transfer pump B due to a broken shaft.
September 13, 1975	106616[a]	September 3, 1975	During a routine shutdown, the start and auxiliary bus de-energized upon turbine trip. The reactor scrammed and the diesel re-energized the bus. During the transient a safety relief valve opened and failed to reset. Steam cutting of the pilot valve caused the valve to fail.
	107415	October 13, 1975	While placing the RHR system in the shutdown cooling mode, the shutdown cooling inboard isolation valve became inoperable. The motor had separated from the gear box.
November 5, 1975 Kewaunee	107506	October 15, 1975	Two of three auxiliary feedwater pumps failed to start due to faulty control switches following a unit trip.
	108076	November 5, 1975	Diesel generator 1 failed to start during testing due to improper operation of a control switch.
	108078[a]	November 5, 1975	Reduced flow was observed from all three auxiliary feed pumps due to resin bead plugging of the pump suction strainers.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
November 5, 1975 Kewaunee (continued)	108836	December 4, 1975	A breaker supplying uninterruptable instrument bus power inadvertently opened, resulting in a reactor trip and loss of one auxiliary feedwater pump. The cause of the breaker opening was not determined.
June 26, 1976 Haddam Neck	115450	June 17, 1976	Power was lost to RHR pump 1B during refueling due to an operator error in attempting to load a 480 V ac bus beyond the capacity of a tie breaker in use at the time.
	115875[a]	June 26, 1976	Loss of offsite power occurred while switching operations were in progress to restore a line to service due to the incorrect location of a backup protection device with respect to a tie breaker. The reactor was shutdown at the time.
	116273	July 5, 1976	Both auxiliary feed pumps failed to develop proper discharge pressure due to vapor binding, probably due to back-leakage from one of the steam generators via a check valve.
	116272	July 20, 1976	Steam line 2 flow indicator failed low as a result of a sensing line leak due to cross-threading of a fitting.
July 7, 1976 Vermont Yankee	115721	June 16, 1976	An operator inadvertently drained the pressure reference log in the vessel water level control system. This resulted in a pressure transient as the feedwater control valves ramped shut and the water level decreased to the scram and ECCS initiation point. The reactor scrammed from 88% power and the HPCI initiated, however, upon initiation the gland seal condenser failed. HPCI did operate successfully throughout the transient.
	115870[a]	July 7, 1976	The reactor main steam relief valves were being tested during a refueling outage. The air operator on 3 of 4 relief valves did not move when air was applied to them. The diaphragm failed due to excessive heating.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
July 20, 1976 Millstone 2	116212[a]	July 20, 1976	Blown control power fuses discovered after a plant trip on July 5, 1976, resulted in the resetting of the safety-related undervoltage trip set points to ensure all 480 V ac motor control centers would operate at all voltages above the trip set points. On July 20, 1976, a main circulating water pump was started which resulted in an in-plant voltage reduction to below the revised trip set point. This isolated the safety-related buses and started the diesel generators. However, each time a major load was tied to the diesel, the revised undervoltage trip set points tripped the load. This resulted at the end of the diesel loading sequence with the diesels tied to the safety-related buses but with all major loads isolated.
	117061	July 24, 1976	The steam-driven auxiliary feedwater pump inlet steam trip valve failed to open due to a sheared shaft. The cause of the shearing was unknown.
	118260	July 29, 1976	A leak was discovered in an instrument line upstream of its isolation valve on the reactor coolant pump B discharge piping. The plant was cooled down and depressurized and the leak repaired.
	117062	August 2, 1976	A leak was discovered in the A charging pump discharge relief valve inlet line at a socket weld.
	117944	August 10, 1976	A complete loss of offsite power occurred during hurricane Belle due to severe salt containment in the plant switchyard.
	117942	August 16, 1976	Diesel generator 12U failed to start due to a failed fuel oil servo booster. The booster was cleaned and the diesel returned to service. The diesel also failed to start for the same reason on August 17 and August 23. A worn leather gasket was finally identified and replaced.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
August 10, 1976 Millstone 1	116269	July 14, 1976	During surveillance testing, the inboard isolation condenser (IC) valve could not be opened, thus rendering the IC inoperable. The valve motor became separated from the valve due to failed nuts.
	116780[a]	August 10, 1976	The gas turbine and the diesel generator were being run as a precaution since Hurricane Belle was passing. Salt buildup on the 345 kV lines caused a plant trip due to a loss of offsite power. The gas turbine tripped immediately and tripped again on restart. An incorrect feed was being used.
	117678	August 30, 1976	While at power, the gas turbine became inoperable for roughly 5 minutes due to an overspeed condition. Inspection of the electronic control associated with the speed switches revealed that several of the components were damaged from overheating. The control was replaced.
November 1, 1976 Quad Cities 2	120443[a]	November 1, 1976	During startup, two electromatic relief valves failed to open given a manual signal. The unit was shutdown. Both valves were inspected and found to be severely corroded. They were rebuilt.
	121072	November 14, 1976	While performing RPS Channel "B" MSIV testing, a half scram signal was not received. One of the RPS limit switches had failed due to the harsh environment.
November 11, 1976 Hatch 1	120290	November 2, 1976	While testing the "1C" diesel generator, an overspeed alarm began flashing erratically. The diesel output breaker tripped; however, the diesel remained in operation, but it was manually tripped. It appeared that the overspeed trip linkage was out of adjustment.
	120293[a]	November 11, 1976	While operating at 85% power both division I and II service water strainers became plugged. The strainer drive motors, which are in continued operation, had tripped. The strainers were manually backflushed twice per shift until the motors were repaired.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
November 11, 1976 Hatch 1 (continued)	120689	November 29, 1976	The RCIC inverter tripped with the reactor at 84% power. A capacitor in the inverter output transformer had shorted. The capacitor was replaced and the inverter returned to service.
	120688	December 9, 1976	A reactor scram was received during a rod pattern change. During the rod pattern exchange, weekly tests were being performed on the turbine trip system. Reactor pressure began to increase and a relief valve partially lifted. The cooldown rate exceeded Technical Specification limits; however the ECCS was not initiated. The relief valve finally reseated at 300 psig.
March 3, 1977 Crystal River 3	122307	February 3, 1977	Decay heat valves DHV-4 and DHV-41 would not open remotely during a cooldown due to the effect of pressure on the gate valve disks. They were opened by hand.
	122358	February 4, 1977	While in cold shutdown, the low range pressure overprotection system was found not armed due to a procedural error.
	122894	February 7, 1977	While in mode 5 and on the decay heat removal system, sodium hydroxide was introduced into the reactor coolant system due to cycling valve BSV-36 with valves DHV-41, DHV-4, and DHV-3 open.
	122308	February 10, 1977	During cleanup of the RCS after dilution with NaOH (see NSIC 122894), the boron concentration was diluted by 230 ppm due to the improper loading of mixed bed resin in lieu of cation resin into the demineralizer.
	123114	February 25, 1977	Main steam relief valve MSV-36 opened 60 psi below its set point. The reason for the set point drift is unknown.
	123150[a]	March 2, 1977	Vital bus B failed due to the failure of inverter B output diode. This caused a reactor trip, turbine trip and the 30% opening of the atmospheric dump valves. The cooldown rate was 164°F in 15 minutes.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
March 3, 1977 Crystal River 3 (continued)	123780	March 7, 1977	HPI loop B was removed from service to repack makeup valve MUV-26.
	123781	March 7, 1977	Turbine driven AFW pump 3B tripped on overspeed when started from the control board with main steam as the supply due to lack of governor response.
	123115	March 8, 1977	Main steam relief valve MSV-35 opened while at power at 985 psig. This is 60 psig below the Technical Specification limit. The cause of the set point drift is unknown.
	124250	March 22, 1977	Following a reactor trip, manual high pressure injection was initiated on HPI Train A. One of the two HPI isolation valves (MUV-24) failed to open due to improper torque switch setting.
April 8, 1977 Duane Arnold	124169	April 5, 1977	During preventive maintenance, 13 CRD hydraulic control unit water level switches would not respond to water level increases. The switches were replaced in kind. The cause of the failure was unknown.
	124222[a]	April 8, 1977	During bench testing of the relief valves, four valves did not lift and two valves lifted at elevated pressures. The cause of the failure was unknown at the time of the reporting.
	124168	April 13, 1977	During annual inspection of the 1G-31 standby diesel, the lower crack shaft main thruster bearing had been wiped. No cause was stated in the report.
July 12, 1977 Zion 2	126473	June 15, 1977	Instrument air isolation valve 2FCV-1A01B failed to close due to a stuck solenoid valve. Impurities in the air supply caused the valve to stick.
	126474	June 26, 1977	Both pressurizer steam space sample isolation valves failed to close during testing. The failures were caused by incorrect closing spring compressive force for one valve and entrapped oil and residue in the diaphragm air space on the other.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
July 12, 1977 Zion 2 (continued)	127384[a]	July 12, 1977	Dummy loads were installed on all pressurizer pressure, RCS loop flow and steam generator level instrumentation. As a result of the dummy signals, pressurizer level decreased until the level was indicating zero when the dummy signals were removed.
	130930	August 11, 1977	Both boric acid transfer pumps were removed from service to replace a valve diaphragm in the suction cross-tie line.
July 15, 1977 Brunswick 2	127091	June 22, 1977	While HPCI was out of service for repairs and calibration, the "2A" RHR pump failed to start during operability test required by the HPCI LCO. A spring in the 2A pump breaker was out of position. The breaker was adjusted and manually closed. The clearance on the pump was then cancelled.
	128569[a]	July 15, 1977	A turbine trip resulted in a reactor scram. Reactor pressure was maintained using safety/relief valves. Safety/relief valve F013E failed to reset resulting in a system blowdown. The corresponding cooldown rate was 136°F/h. A ground was found on the solenoid assembly of the failed valve.
August 31, 1977 Cooper	128906[a]	August 31, 1977	Following a reactor scram due to low water level, HPCI initiated on low water level, but failed to inject into the reactor vessel. The woodward governor actuator had failed.
	130113	September 12, 1977	During normal operation, the #1 diesel generator control power failure annunciator alarmed. Water had leaked into the panel and shorted the power supply for the local annunciators. Since the alarm which monitors abnormal conditions of the diesel was inoperable, the operator manually opened the control power breaker rendering the diesel generator inoperable.
September 24, 1977 Davis-Besse 1	129852	August 24, 1977	Decay heat pump 1-2 was taken out of service to install a union on the component cooling water return line.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
September 24, 1977 Davis-Besse 1 (continued)	130047	August 25, 1977	AFW pump 1-1 cooling water was isolated to install a permanent pressure relief valve on the cooling water discharge line from the pump bearings. This rendered the AFW pump inoperable for the maintenance period. Five days later AFW pump 1-2 was rendered inoperable for the same purpose.
	129851	August 27, 1977	Reactor coolant pump 1-1-2 tripped while in mode 2 at 125 MWt due to damaged B&C phase surge capacitors. The cause of the damage is unknown.
	130048	August 29, 1977	Steam generator 1-2 level exceeded 86% on the operating range level indication. Steam generator drain valve MS 603 failed to open due to an improperly adjusted torque switch. The valve was manually opened.
	129583	August 29, 1977	Both makeup pumps (not the HPI pumps on Davis-Besse) were rendered inoperable due to a blown fuse in the makeup tank low level interlock circuit.
	130051	September 1, 1977	Reactor coolant pump 1-2-1 tripped on low seal injection and component cooling water flow due to an operator error in closing the incorrect instrument air valve.
	130049	September 7, 1977	During power supply switching while on decay heat cooling, decay heat suction valve DH12 closed due to a design deficiency in the valve interlock/control circuit.
	130105	September 17, 1977	Makeup pump 1-2 was removed from service to repair an oil leak on the outboard bearing end plate.
	130788[a]	September 24, 1977	A half-trip of the SFRCS due to unknown causes initiated closure of startup feedwater valve FWSP7A. This resulted in reduced water level in steam generator 2 and subsequent RCS temperature and pressure rise. The pressurizer PORV lifted nine times and then stuck open. The valve stuck open because of rapid cycling caused by the omission of a relay in its control circuit.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
September 24, 1977 Davis-Besse 1 (continued)	130714	October 11, 1977	Twice, source range detector NI-1's indication failed low and then returned to normal. No cause was determined.
	130904	October 11, 1977	RPS Channel 1 was accidentally de-energized during testing due to an error in the test instructions. This resulted in the de-energization of the power supply for NI-2.
	130943	October 16, 1977	The governor for AFW pump 1-2 was found closed during testing. The possible cause was excessive vibration from the startup feed pump motor.
	130773	October 20, 1977	Both AFW pump suctions were found aligned to the deaerator storage tanks without the cooling water supply shifted to the service water system. This would have resulted in greater than 200°F cooling water to the pump bearings.
November 29, 1977 Davis-Besse 1	131719	November 7, 1977	Channel 2 of reactor coolant pump motor 2-2 monitor was determined inoperable during testing due to a defective zenac diode. This channel would not have detected a locked rotor condition had it occurred.
	130942	November 8, 1977	Auxiliary feed pump turbine 1-2 governor vibrated closed due to vibrations from the startup feed pump motor.
	131723	November 17, 1977	AFW valves AF99 and AF608 were discovered closed. This resulted in inoperable SFRCS steam generator to feedwater differential pressure switch inputs. A procedural deficiency was found in the SFRCS monthly test which resulted in the failure to reset the valve logic for these valves.
	132161	November 29, 1977	Power was lost to all four reactor coolant pumps following a temporary loss of 13.8 kV power.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
November 29, 1977 Davis-Besse 1 (continued)	132927[a]	November 29, 1977	Generator main breakers were inadvertently manually opened due to a procedural error shortly after a reactor/turbine trip. This deenergized both 13.8 kV buses. Power was supplied from diesel generator 2 in 7 seconds and normal offsite power was returned within 11 seconds on bus B and 25 seconds on bus A.
	132929	November 29, 1977	During a temporary loss of offsite power, diesel generator 1-1 started but failed to supply power to bus C1 due to the diesel tripping on overspeed due to a combination of two things – improper setting of the governor high speed limit switch and the overspeed trip switch in the low end of the allowed range.
	133058	December 1, 1977	Source range neutron detector NI-1 indication dropped to zero and returned to normal indication two times. No cause had been determined.
	133071	December 4, 1977	All control rods in safety groups 1 and 3 fell. No cause could be found.
	134068	December 4, 1977	RCS Channel 3, Loop 1 T_H indicator TI-RC 3B4 failed high on December 4, December 6, and December 13 and then returned to normal operation on the first two dates. The failures were caused by oxidation on the terminals connecting TI-RC 3B4 to the RPS.
	132926	December 6, 1977	Two times within 11 hours, two 345-kV air circuit breakers on bus K tripped due to a fault on the Ohio Edison Beaver Line. This deenergized startup transformer 02. The unit was operating on the auxiliary transformer at the time. The cause of the trips was attributed to galloping conductors on the transmission line.
	134066	December 7, 1977	BWST Channel 3 Level Transmitter sensing line froze, resulting in a low level channel trip. The sensing line froze due to extremely cold temperatures. The sensing line froze again on December 9.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
November 29, 1977 Davis-Besse 1 (continued)	134067	December 7, 1977	RPS Channel 3, Loop B flow indication failed due to a faulty fuse holder spring. On the next day, the same flow indication failed due to faulty fuse holder cap contact.
December 11, 1977 Davis-Besse 1	131723	November 17, 1977	AFW valves AF99 and AF608 were discovered closed. This resulted in inoperable SFRC steam generator to feedwater differential pressure switch inputs. A procedural deficiency was found in the SFRCS monthly test which resulted in the failure to reset the valve logic for these valves.
	132161	November 29, 1977	Power was lost to all four reactor coolant pumps following a temporary loss of 13.8 kV power.
	132927	November 29, 1977	Generator main breakers were inadvertently manually opened due to a procedural error shortly after a reactor turbine trip. This deenergized both 13.8 kV buses. Power was supplied from diesel generator 2 in 7 seconds and normal offsite power was returned within 11 seconds on bus B and 25 seconds on bus A.
	132929	November 29, 1977	During a temporary loss of offsite power, diesel generator 1-1 started but failed to supply power to bus C1 due to the diesel tripping on overspeed due to a combination of two things — improper setting of the governor high speed limit switch and the overspeed trip switch in the low end of the allowed range.
	133058	December 1, 1977	Source range neutron detector NI-1 indication dropped to zero and returned to normal indication two times. No cause had been determined.
	133071	December 4, 1977	All control rods in safety groups 1 and 3 fell. No cause could be found.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
December 11, 1977 Davis-Besse 1 (continued)	134068	December 4, 1977	RCS Channel 3, Loop 1 T_H indicator TI-RC 3B4 failed high on December 4, December 6, and December 13 and then returned to normal operation on the first two dates. The failures were caused by oxidation on the terminals connecting TI-RC 3B4 to the RPS.
	132926	December 6, 1977	Two times within 11 hours, two 345-kV air circuit breakers on bus K tripped due to a fault on the Ohio Edison Beaver Line. This de-energized startup transformer 02. The unit was operating on the auxiliary transformer at the time. The cause of the trips was attributed to galloping conductors on the transmission line.
	134066	December 7, 1977	BWST Channel 3 Level Transmitter sensing line froze, resulting in a low level channel trip. The sensing line froze due to extremely cold temperatures. The sensing line froze again on December 9.
	134067	December 7, 1977	RPS Channel 3, Loop B flow indication failed due to a faulty fuse holder spring. On the next day, the same flow indication failed due to faulty fuse holder cap contact.
	133706[a]	December 11, 1977	Control over both AFW pumps was lost during testing due to mechanical binding in the governor of one pump and blown control power supply fuses for the speed changer motor on the other pump.
	134323	January 2, 1978	BWST Channel 1 SFAS level indication failed low due to a frozen sensing line. The sensing line froze because the channel sensing line enclosure was inadvertently allowed to run out of fuel. The channel sensing line also froze on January 4 due to extremely cold temperatures.
	134456	January 6, 1978	AFW pump 1-1 turbine speed control was lost due to the incorrect setting of the high speed stop and the use of improper relays in the control circuits.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
December 11, 1977 Davis-Besse 1 (continued)	134321	January 7, 1978	Input circuit from SFRCS steam generator-to-feedwater differential pressure trip for channel 1 failed to the tripped state due to a failed diode.
	134320	January 9, 1978	Diesel generator 1-1 tripped on high crankcase pressure due to a dirty crankcase vent oil collector.
March 20, 1978 Rancho Seco	138830[a]	March 20, 1978	An operator changing a light bulb in a backlighted push button dropped the bulb into the control panel. This shorted out dc power to portions of the plant non-nuclear instrumentation. This resulted in loss of approximately 2/3 of flow temperature and pressure signals and resulted in a reactor trip and subsequent RCS cooldown at 300°F/h. Loss of NNI caused invalid indications and steam generator dryout. Instrument drift subsequently initiated AFW flow and resulted in RCS cooldown.
March 25, 1978 Farley 1	137357	March 2, 1978	Diesel generator 1B failed to reach rated speed within Technical Specification limits during testing due to rust particles in the air start solenoid valves.
	137358	March 8, 1978	Diesel generator 1C failed to start due to corrosion particles in the air start solenoid valves. Diesel 1C had been started for an operability check after removing diesel generator 1B from service for maintenance. Diesel generator 1B was placed back in service and the operability of the remaining ac power sources was demonstrated.
	137359	March 9, 1978	During a test, the ESF B1G sequencer failed to meet the time requirement for picking up service water pumps D and E. The Agistat timer in the sequencer was readjusted.
	137537	March 20, 1978	Main steam isolation valve V002A was made inoperable to prevent inadvertent closing and allow repair of a leaking fitting on the actuator air supply line.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
March 25, 1978 Farley 1 (continued)	138240	March 23, 1978	Diesel generator 1B failed to start within the Technical Specification limit due to the failure to replace the main air start valve pusher assembly (used for normal engine starts) during a previous maintenance. The valve was replaced.
	137305[a]	March 25, 1978	Following a reactor trip, the turbine-driven AFW pump failed to start due to a shut turbine trip/throttle valve. In addition, the motor- and turbine-driven AFW pump bypass valves were found opened in lieu of closed, preventing proper AFW pump flow.
	138185	March 31, 1978	Steam pressure transmitter PT-485 indication failed low due to a failed isolated/nonisolated card. This resulted in inoperability of protection channel 3 steam pressure loops 1, 2, and 3.
	138348	April 18, 1978	Two cells in service water building train A battery bank 1 failed to meet Technical Specification (specific specifications unspecified). No cause for the failures could be determined.
	138346	April 24, 1978	During a unit startup, intermediate range N35 high flux trip set point was found low due to the reduced sensitivity of a replacement intermediate range detector. The high flux trip set point was reset prior to increasing reactor power above 5%.
March 29, 1978 Three Mile Island 2	141097[a]	March 29, 1978	Vital bus 2-1V became de-energized when the alternate source was tripped during SFAS testing and resulted in a blown dc input fuse. This resulted in the opening of the PORV and subsequent RCS depressurization.
	145376	March 29, 1978	Valves NM-V52 and NS-V81 failed to close during testing because manual handwheel pins for both valves were left engaged.
	137916	April 4, 1978	Nuclear service closed cooling water service valve (valve number unspecified in LER abstract) failed due to the malfunction of the associated solenoid operated pilot valve.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
March 29, 1978 Three Mile Island 2 (continued)	142761	April 8, 1978	RCS wide range pressure transmitter RC-3A-PT4 failed due to a moisture-induced short in the associated terminal box. The failure resulted in trips on SFAS channels RC2A1B.
	145375	April 15, 1978	Decay heat closed cooling system valve DC-V103 failed to close during testing due to a failed valve motor.
	139624	April 17, 1978	RPS Channel C tripped on high flux due to failed detector NI-7. NI-7 failed due to damage during initial installation.
	138786	April 19, 1978	Containment isolation valve CA-V3 failed to close during testing due to an incorrect torque switch setting that prevented the valve from fully closing.
	137918	April 23, 1978	Due to the failure of five main steam relief valves to reseat following a reactor trip, the reactor coolant system rapidly cooled down and depressurized. Safety injection was initiated. RCS and pressurizer cooldown rates were exceeded during the transient. The feedwater system response during the transient was slow since initial ICS testing was in progress.
	137919	April 23, 1978	During the transient described in NSIC 137918, several steel liners used to protect the bellows in the discharge piping were ejected. Inadequate design resulted in the use of bellows liners qualified for 180 ft/s steam velocity in a location where velocities of up to 950 ft/s could be experienced.
	138816	April 25, 1978	Diesel generator B tripped due to high crankcase pressure after running 32 minutes. No cause for the trip could be found.
April 13, 1978 Calvert Cliffs	138204	April 10, 1978	Diesel generaotr 12 tripped on overspeed during testing. The cause of the trip was not determined. The diesel was successfully restarted.
	138205	April 10, 1978	Diesel generator 12 service water valve failed to open automatically during testing due to a loose positioner feed back spring linkage. The valve was manually opened. (This failure occurred during the same test in which diesel generator 12 tripped. See NSIC 138204.)

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
April 13, 1978 Calvert Cliffs (continued)	138184	April 11, 1978	Diesel generator 11 output breaker failed to automatically close following a loss of power on 4-kV bus 11. The breaker was manually closed. (Cause was not determined.) The loss of power on the bus was caused by protective relaying opening breakers in the 500-kV switchyard.
	137912	April 12, 1978	A slight leak (3 drops per minute) was found in the charging pump common suction line relief valve weld. The leak was caused by vibration in the line.
	137543[a]	April 13, 1978	Switchyard breaker protective relaying automatically opened breakers which resulted in loss of all offsite power. Diesel generator 11 failed to start and provide power to 4-kV bus 11. Diesel generator 11 was successfully started and loaded about 50 minutes later. No cause for the diesel generator failure to start was found.
	138334	April 17, 1978	The reactor was cooled down to repair an unisolable leak from a cracked weld on RCP 11B middle seal pressure sensing line. The total unidentified RCS leakage was 1.196 gpm. The probable cause of the failure was cycle fatigue due to pump vibration.
	139376	May 3, 1978	125 V dc battery cell 54 was found below the Technical Specification minimum voltage. The cell was recharged but subsequently replaced when its voltage continued to drop.
April 23, 1978 Three Mile Island 2	141098	March 29, 1978	Vital bus 2-1V de-energized due to a failed inverter caused by a blown dc input fuse. This caused a stuck-open PORV and subsequent RCS depressurization.
	145376	March 29, 1978	Containment isolation valves NM-V52 and NS-V81 failed to operate during testing because the manual handwheel pins were left engaged.
	137916	April 4, 1978	A nuclear service closed cooling water valve failed to open during testing due to a failure of the solenoid operated pilot valve.
	142761	April 8, 1978	RCS wide pressure transmitter RC-3A-PT4 failed due to a moisture-induced short circuit in its terminal box. The failed transmitter caused a trip on SFAS channels RC 2A1B.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
April 23, 1978 Three Mile Island 2 (continued)	145375	April 15, 1978	Decay heat closed cooling system valve DC-V103 failed to close during testing due to a failed motor operator.
	139624	April 17, 1978	RPS Channel C tripped on high flux. No cause could be found. The channel again tripped on April 20, 1978, and the failure was determined to be caused by NI-7 detector damage incurred during initial installation.
	138786	April 19, 1978	Containment isolation valve CA-V3 failed to close during testing due to an incorrect torque switch setting. The valve was manually closed.
	137918[a]	April 23, 1978	Following a reactor trip from 30% power, the main steam relief valves did not reseat at the correct pressure. The valves utilized bellows protection liners qualified for 180°F/s in a 950°F/s steam velocity location. The reactor coolant system rapidly cooled down and depressurized. Safety injection was initiated.
	138816	April 25, 1978	Diesel generator B tripped on high crackcase pressure after running 32 minutes. No cause could be found.
	139620	May 20, 1978	Diesel generator B failed to start during testing due to the failure of the vertical shaft coupling between the upper and lower crankshafts caused by the use of improper material.
	139622	May 23, 1978	Diesel generator B tripped on high crankcase pressure during testing due to a partially plugged orifice plate to the vacuum ejector. This resulted in reduced crankcase vacuum. This test was an operability check after the shaft coupling replacements identified in NSIC 139620.
May 14, 1978 St. Lucie 1	142797	April 15, 1978	Three of 45 in-core instrument thimbles remained in the core when the upper guide structure was removed during refueling. The thimbles fractured by fatigue at a stress concentration due to a deep thread at the end of an extension tube.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
May 14, 1978 St. Lucie 1 (continued)	139344	April 23, 1978	The 12 boric acid mix tank level instrument failed high due to improper blowing-down of the sensing line to prevent sensing line blockage. After maintenance and recalibration, the instrument indicated correctly.
	139565[a]	May 14, 1978	Improper switching at a substation, in combination with incorrect wiring of protective relays, resulted in a loss of offsite power. One diesel generator was out of service for maintenance. The other diesel started and provided shutdown power.
	139928	June 8, 1978	CEA No. 68 dropped four times within an 8.5-h period due to failure of its coil power programmer module, integral timer, or 15-V power supply.
July 28, 1978 Beaver Valley 1	140272	July 9, 1978	Boron injection tank recirculation valve failed to close due to worn operator solenoid valve internals.
	140335[a]	July 28, 1978	An electrical fault occurred in the station main transformer resulting in generator, turbine, and reactor trip and safety injection followed four minutes later by loss of offsite power. Both emergency diesels started, but No. 2 diesel generator failed to flash its field. The field flash failure could not be duplicated.
	140209	August 4, 1978	During a load test, the No. 4 station battery charger output breaker tripped before completion of the test. The cause of the trip is unknown.
November 27, 1978 Salem 1	142462[a]	November 27, 1978	Failure of inverter output transformer resulted in the loss of vital bus 1B. This de-energized "RCP Breaker Open" relay in SSPS, initiating a reactor trip. AFW pump 12 (due to loss of vital bus) and AFW pump 13 failed to start. Seven minutes later a safety injection occurred and 1B diesel, 11 charging pump, and 12 RHR pump failed to start due to the failed instrument bus.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
November 27, 1978 Salem 1 (continued)	142837	December 1, 1978	No. 12 steam generator level channel III was found inoperable because of partially clogged sensing lines.
January 12, 1979 Davis-Besse 1	146557	December 30, 1978	CCW heat exchanger 1-1 service water outlet valve SW-1424 failed to open. No cause could be found for the failure. On December 31, 1978, the same valve would not maintain temperature due to slippage and misalignment of the valve linkage.
	146690	January 2, 1979	Main steam valves 106 and 106A to auxiliary feedwater pump 1-1 failed to open due to dirt accumulation on the valve stems resulting from construction activity in the area.
	148614	January 3, 1979	HPI pump 1-1 was declared inoperable due to plugged recirculation line. The recirculation line became plugged due to inability of heat tracing to maintain line temperature above freezing.
	146693	January 6, 1979	Inadvertent SFAS relay actuation resulted in the realignment of decay heat system valves DH9A and DH7A during testing. The relay actuation resulted from a bistable level setting in excess of Technical Specification requirements combined with a noisy constant current test potentiometer within the SFAS cabinet.
	146744[a]	January 12, 1979	Loss of power to vital bus Y2 caused by an accidental grounding of a containment hydrogen analyzer resulted in rapid feedwater reduction and increased reactor power and subsequent reactor and SFRCS trip and feedwater isolation.
	147248	January 15, 1979	Reactor coolant pump 1-2-2 was started with incorrect breaker alignment which caused low voltage relays to trip and de-energize both 4.16 kV essential buses C1 and D1. Both diesel generators started and supplied power to essential loads.
	148320	January 16, 1979	A 1/2-in. nipple on makeup pump 1 gear-driven lube oil pump discharge failed resulting in an oil spray and consequent makeup pump shutdown. Fatigue failure from pipe vibration was suspected as the cause of the failure.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
January 12, 1979 Davis-Besse 1 (continued)	148315	January 30, 1979	Main steam code safety valves SP17A2 and SP17B2 lifted below their set point range during plant load swings. Valve SP17A2 was found to have a loose spindle and was gagged. Valve SP17B2 was tested and found satisfactory and returned to service.
January 18, 1979 Beaver Valley 1	146602	December 22, 1978	Main steam flow capacitor in one of the 1A main steam flow instrumentation channels failed during testing. The capacitor was replaced.
	146603	December 22, 1978	Main steam pressure instrument loop 1A failed due to a failed capacitor caused by a broken lead on a capacitor.
	148763	January 3, 1979	Main steam isolation valve 1C inadvertently closed in 0.5 s, caused by shorting of the fully closed limit switch contacts on the valve because of steam condensation. The valve closure resulted in a reactor trip and safety injection initiation.
	148764[a]	January 18, 1979	Unit load reduction was in progress due to a tripped heater drain pump. Condenser steam dump valves opened causing high steam flow. The valves failed to close because the operators were subjected to excessively cold temperatures as a result of improperly positioned ventilation dampers. The open valves resulted in low steam line pressure and consequent reactor trip and safety injection initiation.
	147433	January 20, 1979	Vital bus 3 failed due to faulty inverter components. This resulted in reactor trip on false indication of reactor coolant pump C opening.
March 29, 1979 Three Mile Island 2	153164[a]	March 28, 1979	Loss of feedwater and subsequent stuck open PORV. Auxiliary feedwater valves were closed for the first eight minutes of the transient; high pressure injection was subsequently throttled due to apparent high pressurizer level. The reactor coolant pumps were tripped 1-2 hours into the transient. The combined effect of these actions resulted in severe core damage.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
April 19, 1979 Oyster Creek	149233	April 2, 1979	Low power physics testing was being performed without the rod worth minimizer in operation.
	149235	April 17, 1979	The "D" recirculation pump was out of service when the "C" recirculation pump tripped. An orderly shutdown was commenced. A relay target was found on the 50SR generator overcurrent relay, and a generator collector ring brush was found burned. The part was repaired and the shutdown terminated.
	149450[a]	April 19, 1979	While testing IC auto-actuation, a reactor high-pressure scram occurred. The feedwater pump failed to start; thus water level decreased to the low-low-low level. The IC was used to facilitate cooldown until the feed system could be started. Isolation of all recirculation pump inlet valves compounded the problem. Faulty procedures are considered the primary contributor to the transients.
	149452	April 19, 1979	During testing of the core spray system, the NZ01A core spray pump failed to start. A fuse failed in the closing control circuit of the breaker for the pump motor. The fuse was replaced and the pump tested successfully.
June 3, 1979 Hatch 1	149962	May 21, 1979	During operability tests, diesel generator 1A was unable to carry less than 50% of its rated load. The synchronizer gear was improperly installed following a modification to the governor. The reactor was in refueling and the 1C diesel was undergoing its five-year preventive maintenance.
	149961[a]	June 3, 1979	Following a scram the HPCI system failed to start given an initiation signal. Water had contaminated the oil system, thus preventing the stop valve from opening. The RCIC system also failed to operate for unspecified reasons.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
June 3, 1979 Hatch 1 (continued)	150117	June 13, 1979	The 13A and B scram discharge volume high level switches were found to be inoperable during testing. An inspection revealed the floats on both switches were bent and binding against the float chamber wall. The switches were repaired and they functioned properly. The plant was in refueling and the redundant switches were operable.
	150505	June 24, 1979	While performing a diesel generator manual start, the diesel generator tripped fifteen minutes after being loaded onto the bus. An initial investigation did not reveal the cause.
June 6, 1979 Crystal River 3	149892	May 9, 1979	Count rate amplifier and rate-of-change amplifier for source range instrument NI-1 was inoperable due to instrument drift.
	148893	May 10, 1979	Count rate amplifier and rate-of-change amplifier for source range instrument NI-2 was inoperable due to instrument drift.
	150882[a]	June 6, 1979	Both diesel generators tripped during testing due to imbalance in reactive load.
September 3, 1979 St. Lucie 1	152187[a]	September 3, 1979	While in cold shutdown during the passage of Hurricane David, a cable fell across the lines of startup transformer B, causing a lockout on the east bus and de-energization of the B startup transformer. The B electrical system was de-energized and the B diesel generator failed to start due to the binding of a relay in the diesel auto start circuitry.
October 2, 1979 Prairie Island 1	152563[a]	October 2, 1979	A tube break of 390 gpm occurred in steam generator 11. The break resembled a classic overpressure break. Two other tubes showed reduction in wall thickness.
November 20, 1979 Brunswick 1	154770	October 25, 1979	During an HPCI component test, the control room operator noticed that the HPCI injection valve could not be operated. The lockwire for the drive gear setscrew was missing. This allowed the drive gear key to move out of its keyway, resulting in valve inoperability. The operator reassembled the drive gear and the valve functioned properly.

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[a] Significant precursor.

Table E.2 (continued)

Significant precursor date and plant	NSIC accession number	Event date	Description
November 20, 1979 Brunswick 1 (continued)	153365	November 15, 1979	The RCIC failed to start during a test after maintenance. A bolt on the steam exhaust valve sheared causing the valve to fail.
	153810[a]	November 20, 1979	Following a reactor scram, the RCIC turbine tripped on mechanical overspeed with HPCI out for maintenance. The turbine was reset and started properly. An investigation after the transient revealed that the tachometer contact was cracked.
	153750	December 5, 1979	While performing the RCIC turbine exhaust diaphragm high pressure function test, it was discovered that the root valves to instruments 1ES1-PS-N012B and D were closed. The valves to redundant instruments were open and operable. It is suspected the root valves were left closed during the last system maintenance.
	154019	December 6, 1979	While performing the HPCI 1000-lb-rated flow test, the system isolated on high suction pressure. The diaphragm was leaking, thus providing a false high pressure signal.
	153751	December 7, 1979	While performing a core spray system component test, the "pump running" annunciator was not received. The root valves for switches for 1-E21-PS-N008B and 9B were found shut. These switches provide an LPCI pump running permissive for automatic ADS actuation. The redundant ADS permissive signal was available.

[a] Significant precursor.

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Descriptions of 169 operational events reported as Licensee Event Reports, which occurred at commercial light-water reactors during 1969–1979 and which are considered to be precursors to potential severe core damage, are presented, along with associated event trees and categorizations and subsequent analyses. The report summarizes work in (1) the development of methods used to screen ~19,400 LER abstracts for potential precursors, (2) the initial screening of those abstracts to determine which should be reviewed in detail, (3) the detailed review of those selected LERs that yielded the 169 events, (4) the categorization of the 169 events, (5) the calculation of function failure estimates based on precursor data, (6) the use of probability of severe core damage estimates to rank precursor events and estimate the frequency of severe core damage, (7) the identification of 52 events considered significant, (8) trends analyses of those significant events, and (9) the identification of the other events of interest that occurred within 1 month of significant events.

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